Maintaining Reliable Supply to the North West Slopes Area

Market modelling report forecasting gross market benefits for the PACR

28 June 2022

Building a better working world

Release Notice

Ernst & Young ("EY") was engaged on the instructions of NSW Electricity Networks Operations Pty Limited, as trustee for NSW Electricity Networks Operations Trust ("Transgrid"), to undertake market modelling of system costs and benefits to assess non-network options for "Maintaining Reliable Supply to the North West Slopes Area" Regulatory Investment Test for Transmission ("NWS RIT-T").

The results of EY's work are set out in this report dated 28 June 2022 ("Report"), including the assumptions and qualifications made in preparing the Report. The Report should be read in its entirety including this release notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. No further work has been undertaken by EY since the date of the Report to update it.

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Modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual outcomes, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved. We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on a future course of action. We provide no assurance that the scenarios we have modelled will be accepted by any relevant authority or third party.

Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenario, and the key assumptions are described in the Report. These assumptions were selected by Transgrid after public consultation. The modelled scenario represents one possible future option for the development and operation of the National Electricity Market, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

EY's liability is limited by a scheme approved under Professional Standards Legislation.

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1. Executive summary

Transgrid has engaged EY to undertake market modelling of system costs and benefits of non-network options related to the "Maintaining Reliable Supply to the North West Slopes Area (NWS)" for the Regulatory Investment Test for Transmission (RIT-T).

This Report forms a supplementary report to the Project Assessment Conclusion Report (PACR) prepared and published by Transgrid[1], and describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid and the modelling methods used. The Report should be read in conjunction with the PACR[1] published by Transgrid.

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with non-network options for the Step Change, Progressive Change and Hydrogen Superpower scenarios issued by the Australian Energy Market Operator (AEMO) Draft 2022 Integrated System Plan (ISP)[2]. In addition, Transgrid has requested to incorporate more recent input and assumptions updates based on new information since the publication of the Draft 2022 ISP, as follows.

- latest committed and anticipated generators from the AEMO Generation Information resource, published in May 2022[3].
- recent announced closure dates for Eraring, Bayswater and Loy Yang coal fired generators[3].

The modelling methodology is consistent with *RIT-T guidelines* published by the Australian Energy Regulator (AER)[4]. To assess the potential least-cost solution, EY's Time Sequential Integrated Resource Planner (TSIRP) model is used. It makes decisions for each hourly trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to bid at their short run marginal cost (SRMC), which is derived from their variable operation and maintenance (VOM) and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or un-planned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, solar PV SAT, CCGT, OCGT[5], large-scale battery, pumped hydro energy storage (PHES) and hydrogen turbine technology (only applied in the Hydrogen Superpower scenario).
- the withdrawal of existing generation on a least-cost basis, often to meet the emissions budgets assumed in the modelled scenarios.

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[1] Transgrid, *Maintaining Reliable Supply to the North West Slopes area PACR*. Available at: https://www.transgrid.com.au/projects-innovation/north-west-slopes-area-supply. Accessed 21 June 2022.

[2] Note that while most of the assumptions are from the 2021 Inputs and Assumptions workbook published on 10 December 2021, some assumptions like the timing of major upgrades are based on the Draft 2022 ISP outcomes. AEMO, *2022 Draft ISP Consultation*, available at https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation, and AEMO, *Current inputs, assumptions and scenarios*, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed on 21 June 2022.

[3] AEMO generation information and expected closure years, May 2022, available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

[4] AER, August 2020. *RIT-T guidelines*. Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable/final-decision Accessed 21 June 2022

[5] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Combined-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine.

The hourly decisions consider certain operational constraints that include:

- supply must equal demand in each region for all trading intervals plus a reserve margin, with unserved energy (USE) costed at the value of customer reliability (VCR)[6],
- minimum loads for coal generators,
- interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),
- maximum and minimum storage (conventional storage hydro, PHES and large-scale battery) reservoir limits and cyclic efficiency,
- new entrant capacity build limits for wind and solar for each renewable energy zone (REZ) where applicable, and PHES in each region,
- carbon budget constraints, as defined in the ISP for the modelled scenarios,
- renewable energy targets where applicable by region or NEM-wide, and
- other constraints such as network thermal and stability constraints, as defined in the Report.

From the hourly time-sequential modelling we computed the following costs, as defined in the RIT-T guidelines:

- capital costs of new generation capacity installed (capex),
- total fixed operation and maintenance (FOM) costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary (demand-side participation, DSP) and involuntary load curtailment (unserved energy, USE),
- transmission expansion costs associated with REZ development.

The forecast gross market benefits capture the impact of transmission losses to the extent that losses across interconnectors and intra-connectors affect the generation that needs to be dispatched in each trading interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including PHES and large-scale battery between each NWS option and the counterfactual Base Case.

For each simulation with a NWS option and in a matched no augmentation counterfactual (referred to as the Base Case), we computed the sum of these cost components and compared the difference between each option and the Base Case. The difference in present values of costs is the forecast gross market benefits[7] due to the presence of the corresponding option, as defined in the RIT-T. For all scenarios, benefits presented are discounted to June 2021 using a 5.5% real, pre-tax discount rate as selected by Transgrid, consistent with the value applied by AEMO in the Draft 2022 ISP[2].

Table 1 below summarises the details of the modelled options. Transgrid has advised EY to maintain the confidentiality of the modelled options. As such, battery size information is withheld and no dollar value results are provided in this report. In addition, the y-axis in all the comparison charts throughout the Report has been removed.

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[6] Based on AER, December 2021, *Values of Customer Reliability Final report on VCR values.* These are the same values applied in AEMO's Draft 2022 ISP, available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf

[7] In this Report we use the term *gross market benefit* to mean "market benefit" as defined in the AER's *Cost benefit analysis guidelines*, and "net economic benefit" in the same manner defined in the guidelines.

Table 1: Summary of the options

Option	Commissioning date	Description
Option 3B	1 July 2029	Large-scale battery 100% battery arbitrage during the year except summer (mid-November to mid-March)
Option 5A	1 July 2025	Large-scale battery 100% battery arbitrage during the year, no battery arbitrage during summer and majority battery arbitrage during June
	1 July 2029	Large-scale battery 100% battery arbitrage during the entire year
Option 5B	1 July 2024	Large-scale battery Until mid-November 2025: 100% arbitrage during the year except summer, in which a small capacity is reserved for network support From mid-November 2025 to mid-November 2029: a small arbitrage capability during summer, mostly able to arbitrage during June and full arbitrage capability for the rest of the year From mid-November 2029: a small capacity is reserved for network support during summer, and full arbitrage during the rest of the year
Option 5C	1 July 2024	Similar operation to Option 5B, except for no battery arbitrage during summer from mid-November 2025 to mid-November 2029

The difference in forecast market benefits across scenarios varies with the option; Progressive Change has the highest forecast market benefits for all options, while Step Change has the lowest forecast market benefits. The breakdown of forecast gross market benefits by category for all modelled options in the three modelled scenarios are shown in Figure 1 to Figure 3.

Figure 1: Composition of forecast total gross market benefits for all options – Step Change

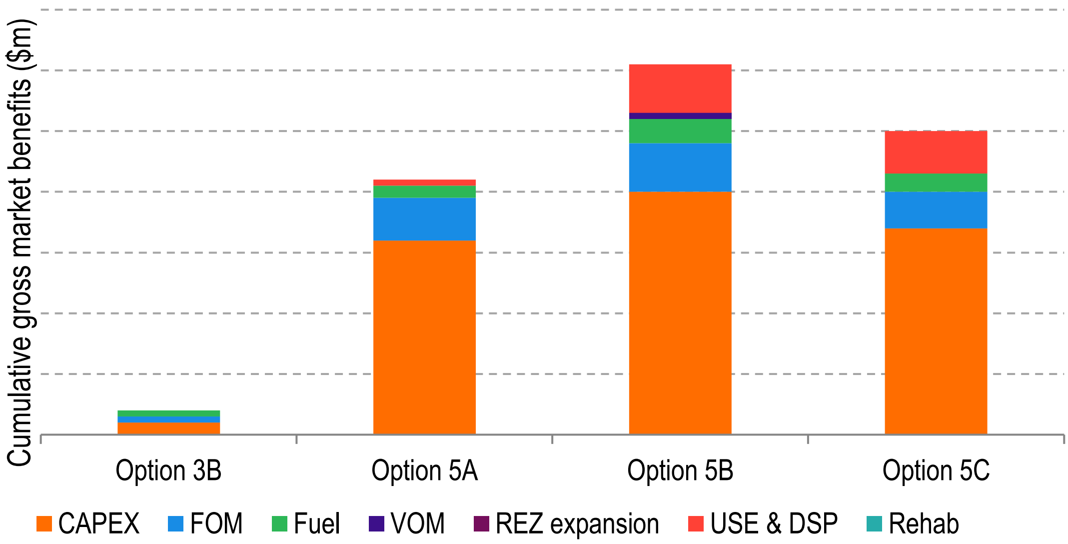


Figure 2: Composition of forecast total gross market benefits for all options – Progressive Change

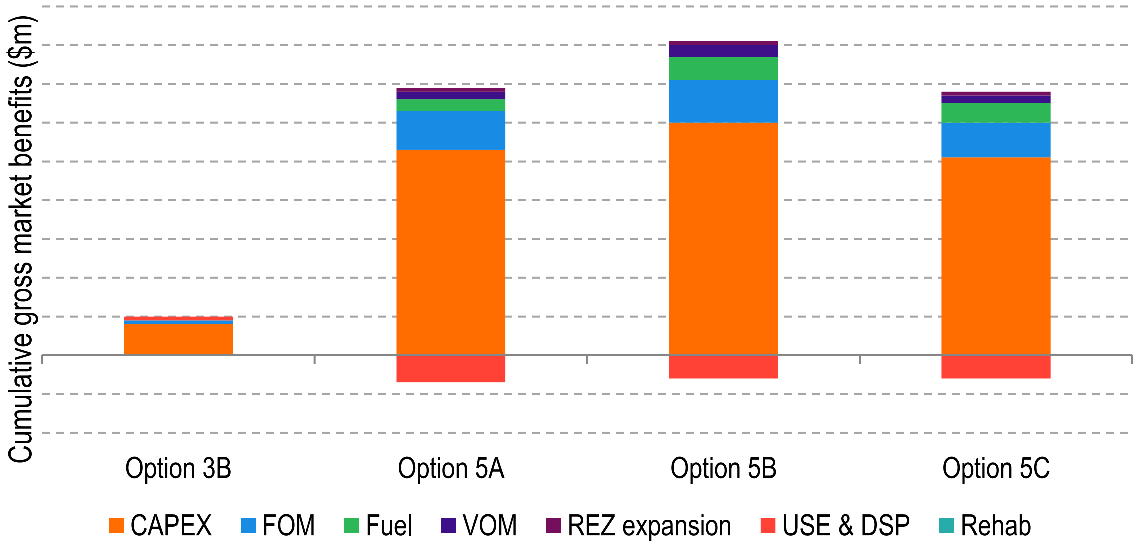
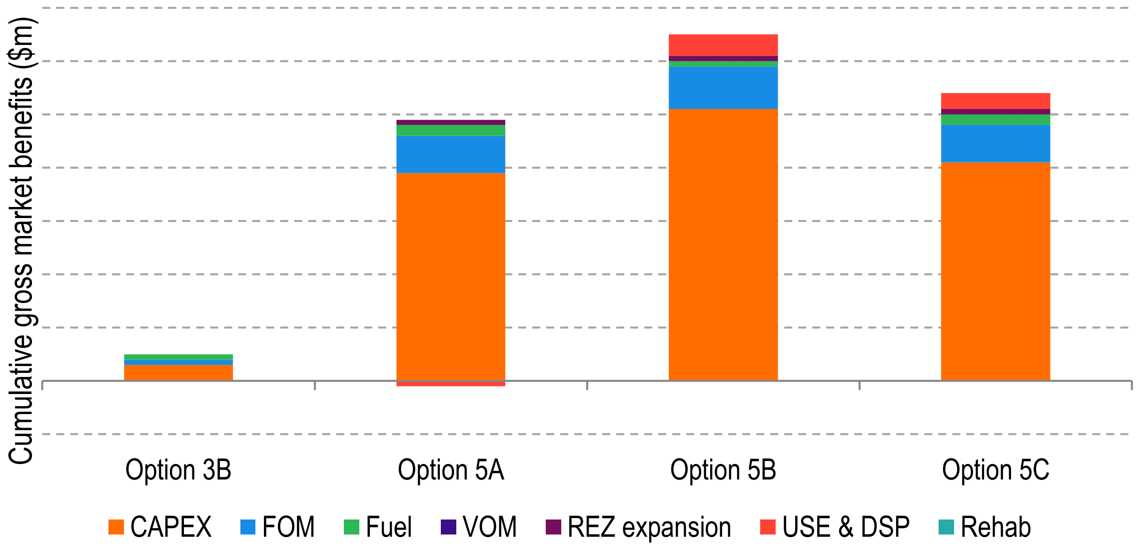


Figure 3: Composition of forecast total gross market benefits for all options – Hydrogen Superpower



The sources of forecast benefits and the key drivers are as follows:

- Capex and FOM cost savings are the largest source of forecast market benefits in all scenarios. Cost savings from avoided USE and DSP are forecast to be relatively high with Options 5B and 5C in the Step Change and Hydrogen Superpower scenarios, while the Progressive Change scenario is expected to incur some costs associated with increased USE and DSP with all options relative to the Base Case.
- All options are assumed to have arbitrage capability during winter, whereas some options can also provide arbitrage during summer. This results in avoiding some OCGT build which is required in the Base Case in the Progressive Change scenario. This is expected to result in early benefits for this option in this scenario, as opposed to the later benefits in other scenarios, leading to higher benefits in the Progressive Change scenario.

2. Introduction

Transgrid has engaged EY to undertake market modelling of system costs and benefits of non-network options related to the "Maintaining Reliable Supply to the North West Slopes Area (NWS)" RIT-T.

This Report forms a supplementary report to the broader PACR published by Transgrid[1]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid and the modelling methods used. The Report should be read in conjunction with the PACR Published by Transgrid.

EY computed the least-cost generation dispatch and capacity development plan for the NEM associated with options using input assumptions generally derived from the AEMO Draft 2022 ISP[2]. In addition, Transgrid has requested to incorporate the most recent input and assumptions since the publication of the Draft 2022 ISP, as follows:

- Latest committed and anticipated generators from the AEMO Generation Information, published in May 2022[3].
- Recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[3].

The options were defined by Transgrid and are described in detail in the PACR. This is an independent study, in which the modelling methodology follows the RIT-T guidelines published by the AER[4]. The Report should be read in conjunction with the Transgrid PACR[1].

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of forecast gross market benefits. The categories of gross market benefits modelled are changes in:

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment,
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model.

Each category of gross market benefits is computed annually across a 19-year modelling period from 2023-24 to 2041-42. Benefits presented are discounted to June 2021 using a 5.5% real, pre-tax discount rate as selected by Transgrid. This value is consistent with the value applied by AEMO in the Draft 2022 ISP[2].

This modelling considers non-network options as shown in Table 2. Transgrid has advised EY to maintain the confidentiality of the modelled options. As such, battery size information is withheld and no dollar value results are provided in this report. In addition, the y-axis in all the comparison charts throughout the Report have been removed.

Table 2: Summary of the options

Option	Commissioning date	Description
Option 3B	1 July 2029	Large-scale battery 100% battery arbitrage during the year except summer (specifically, mid-November to mid-March)
Option 5A	1 July 2025	Large-scale battery 100% battery arbitrage during the year except no battery arbitrage during summer and majority battery arbitrage during June
	1 July 2029	Large-scale battery 100% battery arbitrage during the entire year
Option 5B	1 July 2024	Large-scale battery Until mid-November 2025: 100% arbitrage during the year except summer which a small capacity is reserved for network support From mid-November 2025 to mid-November 2029: a small arbitrage capability during summer, mostly able to arbitrage during June and full arbitrage capability for the rest of the year From mid-November 2029: a small capacity is reserved for network support during summer, and full arbitrage during the rest of the year
Option 5C	1 July 2024	Similar operation to Option 5B, except for no battery arbitrage during summer from mid-November 2025 to mid-November 2029

The forecast gross market benefits of each option need to be compared to the cost of the relevant option to determine the forecast net economic benefit for that option. The determination of the preferred option is also dependent on option costs and was conducted outside of this Report by Transgrid, by incorporating the forecast gross modelled market benefits into the calculation of net economic benefits. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[4].

The Report is structured as follows:

- Section 3 describes options, assumptions and scenarios inputs modelled in this study.
- Section 4 provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.
- Section 5 outlines model design and input data related to representation of the transmission network, transmission losses and demand.
- Section 6 provides an overview of model inputs and methodologies related to supply of energy.
- Section 7 presents the NEM capacity and generation outlook without NWS options.
- Section 8 presents the forecast gross market benefits for each option. It is focussed on identifying and explaining the key sources of forecast gross market benefits of the preferred option, while providing a summary of other options.

3. Scenario assumptions

3.1 Key assumptions for modelled Scenarios

The options proposed by Transgrid have been assessed under the Step Change, Progressive Change and Hydrogen Superpower scenarios from the Draft 2022 ISP[2], as directed by AEMO to Transgrid, and summarised in Table 3. Transgrid has requested to incorporate modifications to AEMO's input and assumptions based on updated information since the publication of the Draft 2022 ISP, as follows:

- Latest committed and anticipated generators from the AEMO Generation Information, published in May 2022[3].
- Recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[3].

Table 3: Overview of key input parameters in the Step Change, Progressive Change and Hydrogen Superpower scenarios

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
Underlying consumption	ESOO 2021[8] (ISP 2022) - Step Change	ESOO 2021[8] (ISP 2022) - Progressive Change	ESOO 2021[8] (ISP 2022) - Hydrogen Superpower
Committed and anticipated generation	Latest committed and anticipated generators from the Generation Information, published in May 2022[3].		
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PHES large-scale batteries and hydrogen turbine	2021 Inputs and Assumptions Workbook[9] - Step Change	2021 Inputs and Assumptions Workbook[9] - Progressive Change	2021 Inputs and Assumptions Workbook[9] - Hydrogen Superpower
Retirements of coal-fired power stations	2021 Inputs and Assumptions Workbook[9] – Step Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives. Updated to reflect recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[2]	2021 Inputs and Assumptions Workbook[9] - Progressive Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030. Updated to reflect recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[2]	2021 Inputs and Assumptions Workbook[9] – Hydrogen Superpower: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives. Updated to reflect recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[2]
Gas fuel cost	2021 Inputs and Assumptions Workbook[9] - Step Change: Lewis Grey Advisory 2020, Step Change	2021 Inputs and Assumptions Workbook[9] - Progressive Change: Lewis Grey Advisory 2020, Central	2021 Inputs and Assumptions Workbook[9] – Hydrogen Superpower: Lewis Grey Advisory 2020, Step Change
Coal fuel cost	2021 Inputs and Assumptions Workbook[9] - Step Change: Wood Mackenzie, Step Change	2021 Inputs and Assumptions Workbook[9] - Progressive Change: Wood Mackenzie, Central	2021 Inputs and Assumptions Workbook[9] – Hydrogen Superpower: Wood Mackenzie, Step Change
NEM carbon budget	2021 Inputs and Assumptions Workbook[9] - Step Change: 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook[9] - Progressive Change: 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook[9] – Hydrogen Superpower: 453 Mt CO_2-e 2023-24 to 2050-51

[8] AEMO, *National Electricity and Gas Forecasting*, http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational,

[9] *2021 Inputs and Assumptions Workbook v3.3*, https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed on 21 June 2022.

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
Victoria Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030[9] VRET 2 including 600 MW of renewable capacity by 2025[9]		
Queensland Renewable Energy Target (QRET)	50% by 2030[9]		
Tasmanian Renewable Energy Target (TRET)	100% by 2022, 150% by 2030 and 200% Renewable generation by 2040[9]		
NSW Electricity Infrastructure Roadmap	12 GW NSW Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the Draft 2022 ISP and 2 GW of long duration storage (8 hrs or more) by 2029-30[9]		
NSW to Queensland Interconnector Upgrade (QNI Minor)	QNI minor commissioned by July 2022[9]		
Victoria to NSW Interconnector Upgrade (VNI Minor)	VNI Minor commissioned by December 2022[9]		
Victorian SIPS	300 MW/450 MWh, 250 MW for SIPS service during summer. In the summer months the remaining 50 MW can be deployed in the market on a commercial basis, in the winter months the full capacity is available. From April 2032 the full capacity is available to the market.[9]		
EnergyConnect	Draft 2022 ISP anticipated project[2]: EnergyConnect commissioned by July 2025		
Western Victoria Transmission Network Project	Draft 2022 ISP[2] anticipated project: Western Victoria upgrade commissioned by November 2025		
HumeLink	Draft 2022 ISP[2] outcome - Step Change: HumeLink commissioned by July 2028	Draft 2022 ISP[2]. outcome - Progressive Change: HumeLink commissioned by July 2035	Draft 2022 ISP[2]. outcome - Hydrogen Superpower: HumeLink commissioned by July 2027
New-England REZ Transmission	Draft 2022 ISP outcome[2] - Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	Draft 2022 ISP outcome[2] - Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	Draft 2022 ISP outcome[2] - Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027 and New England REZ Extension commissioned by July 2031
Marinus Link	Draft 2022 ISP[2] outcome:1st cable commissioned by July 2029 and 2nd cable by July 2031		
QNI Connect	Draft 2022 ISP[2] outcome - Step Change: QNI Connect commissioned by July 2032	Draft 2022 ISP[2] outcome - Progressive Change: QNI Connect commissioned by July 2036	Draft 2022 ISP[2] outcome - Hydrogen Superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030
VNI West	Draft 2022 ISP[2] outcome - Progressive Change: VNI West commissioned by July 2031	Draft 2022 ISP[2] outcome - Progressive Change: VNI West commissioned by July 2038	Draft 2022 ISP[2] outcome - Hydrogen Superpower: VNI West commissioned by July 2030
Snowy 2.0	Snowy 2.0 is commissioned by December 2026[9]		

4. Methodology

4.1 Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 19 years from 2023-24 to 2041-42. The modelling methodology follows the RIT-T guidelines published by the AER[4].

Based on the full set of input assumptions, the TSIRP model makes decisions that minimise the overall cost to supply the electricity demand for the NEM over the entire modelling period, with respect to:

- capex,
- FOM,
- VOM,
- fuel usage,
- DSP and USE,
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied and are calculated dynamically within the model.

To determine the least-cost solution, the model makes decisions for each hourly[10] trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to run at their SRMC, which is derived from their VOM and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (subject to planned or unplanned outages or variable renewable availability), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, offshore wind, solar PV SAT, CCGT, OCGT, large-scale battery and PHES[5]. Hydrogen turbine technology is only modelled as a new generation option in the Hydrogen Superpower scenario.

These hourly decisions take into account constraints that include:

- supply must equal demand in each region for all trading intervals, while maintaining a reserve margin, with USE costed at the VCR[6],
- minimum loads for some generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),
- maximum and minimum storage reservoir limits (for conventional storage hydro, PHES and large-scale battery),
- new entrant capacity transmission and resource limits for wind and solar in each REZ and costs associated with increasing these limits and PHES in each region,
- emission and carbon budget constraints, as defined for each scenario,
- renewable energy targets where applicable by region or NEM-wide.

[10] Whilst the NEM is dispatched on five-minute intervals, the model resolution is hourly as a compromise between managing computation time while still capturing the renewable and storage resources in sufficient detail for the purposes of the modelling.

The model includes key intra-regional constraints in NSW through modelling of zones with intra-regional limits and losses. Within these zones and within regions, no further detail of the transmission network is considered. More detail on the transmission network representation is given in Section 5.

The model factors in the annual costs, including annualised capital costs, for all new generator capacity and the model decides how much new capacity to build in each region to deliver the least-cost market outcome.

The model meets the specified carbon budget assumed in each scenario at least cost, which may be by either building new lower emissions plant or reducing operation of higher emissions plant, or both.

There are three main types of generation that are scheduled by the model:

- Dispatchable generators, typically coal, gas and liquid fuel which are assumed to have unlimited energy resource in general. An assumed energy limit is placed on coal-fired power stations where specified in the Draft 2022 ISP dataset[9]. The running cost for these generators is the sum of the VOM and fuel costs. FOM costs are another component of the running cost of generators contributing to potential earlier economic retirements[11]. Coal generators and some CCGTs have minimum loads to reflect operational stability limits and high start-up costs and this ensures they are always online when available. This is consistent with the self-commitment nature of the design of the NEM. On the other hand, peaking generators have no minimum operating level and start whenever the cost of supply is at or above their variable costs and operate for a minimum of one hour.
- Wind and solar generators are fully dispatched according to their available variable resource in each hour, unless constrained by oversupply or network limitations.
- Storage plant of all types (conventional hydro generators with storages, PHES, large-scale battery and Virtual Power Plants (VPPs)) are operated to minimise the overall system costs. This means they tend to generate at times of high cost of supply, e.g., when the demand for power is high, and so dispatching energy-limited generation will avoid utilisation of high-cost plant such as gas-fired or liquid fuel generators. Conversely, at times of low supply cost, e.g., when there is a prevailing surplus of renewable generation capacity, storage hydro preserves energy and PHES and large-scale battery operate in pumping or charging mode.

4.2 Reserve constraint in long-term investment planning

The TSIRP model ensures there is sufficient dispatchable capacity in each region to meet peak demand by enforcing regional minimum reserve levels to allow for generation contingencies, which can occur at any time.

All dispatchable generators in each region are eligible to contribute to reserve (except PHES, VPPs and large-scale battery[12]) and headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the amount of reserve carried, and provides reserve from the lowest cost providers, including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

In the modelling presented in this Report, a consecutive contingency reserve requirement was applied with a high penalty cost. This amount of reserve ensures there is sufficient capacity for operational reliability in the event that conditions vary from the perfect-foresight optimisation model (e.g., variability in production from variable renewable energy sources, different forced

[11] Note that earlier coal retirements in TSIRP are an outcome of the least cost optimisation rather than revenue assessment.

[12] PHES and large-scale battery storages are usually fully dispatched during the peak demand periods and thus will be unable to contribute to reserve. In the event that they are not dispatched fully, it is likely that they will have insufficient energy in storage.

outage patterns, sub-optimal operation of storage). This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size.[13]

There are three geographical levels of reserve constraints applied:

- Reserve constraints are applied to each region.
- The model ensures that interconnector headroom is backed by spare capacity in the neighbouring regions through an additional reserve constraint.
- In New South Wales, where the major proportion of load and dispatchable generation is concentrated in the Central New South Wales (NCEN) zone, the same rules are applied as for the New South Wales region except headroom on intra-connectors between adjacent zones does not contribute to reserve. This is because even if there is headroom on the NCEN intra-connectors, it is likely that the flows from the north and south into NCEN reflect the upstream network limits. However, intra-connectors still implicitly contribute to reserve because increased flow can displace dispatchable generators within NCEN allowing them to contribute to reserve.

4.3 Cost-benefit analysis

From the hourly time-sequential modelling the following categories of costs defined in the RIT-T are computed:

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment, called DSP and USE,
- transmission expansion costs associated with REZ development.

For each scenario a matched no option counterfactual (referred to as the Base Case) long term investment plan is simulated. The changes in each of the cost categories are computed as the forecast gross market benefits due to the option, as defined in the RIT-T.

Each component of gross market benefits is computed annually over the 25-year modelling period. In this Report, we summarise the benefit and cost streams using a single value computed as the Net Present Value (NPV)[14], discounted to June 2021 at a 5.5% real, pre-tax discount rate as selected by Transgrid, consistent with the Draft 2022 ISP.[9]

The forecast gross market benefits of each option need to be compared to the relevant option cost to determine whether there is a positive forecast net economic benefit. The determination of the forecast net economic benefit and preferred option was conducted outside of this Report by Transgrid[1] using the forecast gross market benefits from this Report and other inputs. All references to the preferred option in this Report are in the sense defined in the RIT-T guidelines as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[4], as identified in the PACR[1].

[13] Testing confirmed that this assumption does not affect outcomes as a reserve constraint is unlikely to bind in lower demand intervals.

[14] We use the term net present value rather than present value as there are positive and negative components of market benefits captured; however, we do not consider augmentation costs.

5. Transmission and demand

5.1 Regional and zonal definitions

Transgrid elected to split NSW into sub-regions or zones in the modelling presented in this Report[15], as listed in Table 4. In Transgrid's view, enables better representation of intra-regional network limitations and transmission losses in the relevant parts of the network.

Table 4: Regions, zones and reference nodes

Region	Zone	Zonal Reference Node
Queensland	Queensland (QLD)	South Pine 275 kV
New South Wales	Northern New South Wales (NNS)	Armidale 330 kV
	Central New South Wales (NCEN)	Sydney West 330 kV
	South-West New South Wales (SWNSW)	Darlington Point 330 kV
	Canberra	Canberra 330 kV
	Bannaby	Bannaby 330 kV
	Yass	Yass 330 kV
	Wagga	Wagga 330 kV
	Lower Tumut	Lower Tumut 330 kV
	Snowy (Maragle)	Snowy (Maragle) 330 kV
	Upper Tumut	Upper Tumut 330 kV
Victoria	Murray	Murray 330 kV
	Dederang	Dederang 330 kV
	Victoria (VIC)	Thomastown 66 kV
South Australia	South Australia (SA)	Torrens Island 66 kV
Tasmania	Tasmania (TAS)	Georgetown 220 kV

The borders of each zone or region are defined by the cut-sets listed in Table 5, as defined by Transgrid. Dynamic loss equations are defined between reference nodes across these cut-sets.

Table 5: Key cut-set definitions

Border	Lines
NNS-NCEN	Line 88 Muswellbrook - Tamworth Line 84 Liddell - Tamworth Line 96T Hawks Nest - Taree Line 9C8 Stroud - Brandy Hill

[15] Transgrid, *HumeLink PACR market modelling*, Available at: https://www.transgrid.com.au/media/vqzdxwl3/humelink-pacr-ey-market-modelling-report.pdf, accessed 21 June 2022.

Border	Lines
NCEN-Canberra	Line 61 Gullen Range - Bannaby Line 3W Kangaroo Valley - Capital Line 4/5 Yass - Marulan Line 973 Yass - Cowra Line 999 Yass - Cowra Line 98J Shoalhaven - Evans Lane Line 28P West Tomerong - Evans Lane and new HumeLink lines for each option
Canberra/Yass-Bannaby	Line 61 Gullen Range - Bannaby Line 3W Kangaroo Valley - Capital Lines 4 &5 Yass - Marulan and new HumeLink lines from Maragle/Wagga to Bannaby for each option
Snowy cut-set	Line 01 Upper Tumut to Canberra Line 2 Upper Tumut to Yass Line 07 Lower Tumut to Canberra Line 3 Lower Tumut to Yass
Wagga-SWNSW	Line 63 Wagga - Darlington Pt Line 994 Yanco - Wagga Line 99F Yanco - Uranquinty Line 99A Finley - Uranquinty Line 997/1 Corowa - Albury New 330 kV double circuit from Wagga - Dinawan (after assumed commissioning of EnergyConnect) New 500 kV double circuit from Wagga - Dinawan (after assumed commissioning of VNI West)
VIC-SWNSW	Line 0X1 Red Cliffs - Buronga New Red Cliffs - Buronga (after assumed commissioning of EnergyConnect) New 500 kV double circuit from Kerang - Dinawan (after assumed commissioning of VNI West)
VNI cut-set	Line 060 Jindera - Wodonga Line 65 Upper Tumut - Murray Line 66 Lower Tumut - Murray VIC-SWNSW cut-set (listed above)
SWNSW-SA	New 330 kV double circuit from Buronga - Robertstown (after assumed commissioning of EnergyConnect)

Table 6 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by Transgrid.

Table 6: Key cut-set limits (MW)

Options	Bidirectional limit (MW)
Snowy cut-set	3,080
Snowy cut-set + HumeLink lines	5,372
Canberra/Yass - Bannaby cut-set	4,900
Canberra-NCEN cut-set	4,500
Bannaby-NCEN	4,500

Table 7 summarises the VNI cut-set limits across the modelling period which are consistent with AEMO's 2021 Input and Assumptions Workbook [16]. The VNI cut-set limits change with the Victorian SIPS contract ending in March 2032, and the commissioning of VNI West. The VNI West timing differs between scenarios[17] and hence the timing in VNI cut-set limit changes will also differ between scenarios.

Table 7: VNI cut-set limits[16]

Description	Import limit (MW)	Export limit (MW)
Original limits	400 all periods	870 peak demand 1,000 summer 1,000 winter
Post Victorian SIPS contract	-150 peak demand[18]	Unchanged
Post VNI West commissioning	+1,200 all periods[18]	+1,930 all periods[18]

5.2 Interconnector and intra-connector loss models

Dynamic loss equations for the existing network are generally sourced from AEMO's *Regions and Marginal Loss Factors*[19]. New dynamic loss equations are computed for several conditions, including:

- when a new link is defined e.g., NNS-NCEN, SA-SWNSW (EnergyConnect), Bannaby-NCEN,
- when an interconnector definition changes with the addition of new reference nodes e.g. VNI now spans VIC-SWNSW and VIC-DED instead of VIC-NSW,
- all the equivalenced lines between the modelled nodes in Canberra, through their equivalent resistance, and
- when future upgrades involving conductor changes are modelled e.g., VNI West, QNI Connect and Marinus Link.

The network snapshots to compute the loss equations were provided by Transgrid.

5.3 Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 8. The following interconnectors are included in the left-hand side of constraint equations which may restrict them below the notional limits specified in this table:

- Heywood + Project EnergyConnect (PEC) has combined transfer export and import limits of 1,300 MW and 1,450 MW. The model will dispatch across the two links to minimise costs.

[16] AEMO, *2021 Inputs and Assumptions Workbook v3.3*, https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, Accessed on 22 June 2022.
[17] AEMO, *Draft 2022 Integrated System Plan*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed 21 June 2022.
[18] The overall limit is the original limit plus the change
[19] AEMO, *Marginal Loss Factors for the 2018-19 Financial Year*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries. Accessed 21 June 2022.

Table 8: Notional interconnector capabilities used in the modelling (sourced from AEMO Draft 2022 ISP[9])

Interconnector (From node – To node)	Import[20] notional limit	Export[21] notional limit
QNI[22]	1,205 MW peak demand 1,165 MW summer 1,170 MW winter	685 MW peak demand 745 MW summer/winter
QNI Connect 1[23]	2,285 MW peak demand 2,245 MW summer 2,250 MW winter	1,595 MW peak demand 1,655 MW summer/winter
QNI Connect 2[23]	3,085 MW peak demand 3,045 MW summer 3,050 MW winter	2,145 MW peak demand 2,205 MW summer/winter
Terranora (NNS-SQ)	130 MW peak demand 150 MW summer 200 MW winter	0 MW peak demand 50 MW summer/winter
EnergyConnect (SWNSW-SA)	800 MW	800 MW
Heywood (VIC-SA)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)
Murraylink (VIC-SA)	200 MW	220 MW
Basslink (TAS-VIC)	478 MW	478 MW
Marinus Link (TAS-VIC)	750 MW for the first stage and 1,500 MW after the second stage	750 MW for the first leg and 1,500 MW after the second leg

NSW has been split into zones with the following limits imposed between the zones defined in Table 9.

Table 9: Intra-connector notional limits imposed in modelling for New South Wales

Intra-connector (From node – To node)	Import notional limit	Export notional limit
NCEN-NNS	1,177 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the Draft 2022 ISP[2].	1,377 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the Draft 2022 ISP[2].
WAG-SWNSW (provided by Transgrid)	300 MW (before EnergyConnect) 1,100 MW (after EnergyConnect) 1,900 MW (after HumeLink) 3,000 MW (after VNI West)	500 MW (before EnergyConnect) 1,300 MW (after EnergyConnect) 2,100 MW (after HumeLink) 2,700 MW (after VNI West)

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20 Import refers to power being transferred from the 'To node' to the 'From node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g., import along QNI implies southward flow and import along Heywood and EnergyConnect implies eastward flow.

21 Export refers to power being transferred from the 'From node' to the 'To node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g., export along QNI implies northward flow and export along Heywood and EnergyConnect implies westward flow.

22 Flow on QNI may be limited due to additional constraints.

23 AEMO, 10 December 2021. *Appendix 5: Network Investments (Appendix to Draft 2022 ISP for the National Electricity market)*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed 21 June 2022.

5.4 Demand

The TSIRP model captures operational demand (energy consumption which is net of rooftop PV and other non-scheduled generation) diversity across regions by basing the overall shape of hourly demand on nine historical financial years ranging from 2010-11 to 2018-19.

Specifically, the key steps in creating the hourly demand forecast are as follows:

- the historical underlying demand has been calculated as the sum of historical operational demand and the estimated rooftop PV generation based on historical monthly rooftop PV capacity and solar insolation and historical data for other non-scheduled generation,
- the nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region (scenario-dependent),
- the nine reference years are repeated sequentially throughout the modelling horizon as shown in Figure 4.
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles, domestic battery and other small non-scheduled generation) to get a projection of hourly operational demand.

Figure 4: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2023-24	2014-15
2024-25	2015-16
2025-26	2016-17
2026-27	2017-18
2027-28	2018-19
2028-29	2010-11
2029-30	2011-12
2030-31	2012-13
2031-32	2013-14
2032-33	2014-15
2033-34	2015-16
2034-35	2016-17
2035-36	2017-18
2036-37	2018-19
…	…
2039-40	2012-13
2040-41	2013-14
2041-42	2014-15

This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to distributed PV uptake, we generally see the peak operational demand intervals shifting later in the day throughout the forecast.

The reference year pattern is also consistent with site-specific hourly large-scale wind and solar availability (see Section 6.1) and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and distributed PV availability.

Transgrid selected demand forecasts from the ESOO 2021[8] consistent with the relevant scenarios in the Draft ISP 2022[9] which are used as inputs to the modelling. Figure 5 and Figure 6 show the NEM operational energy and distributed PV (rooftop PV and small-scale non-scheduled PV) for the modelled scenarios.

Figure 5: Annual operational demand in the modelled scenarios for the NEM[8]

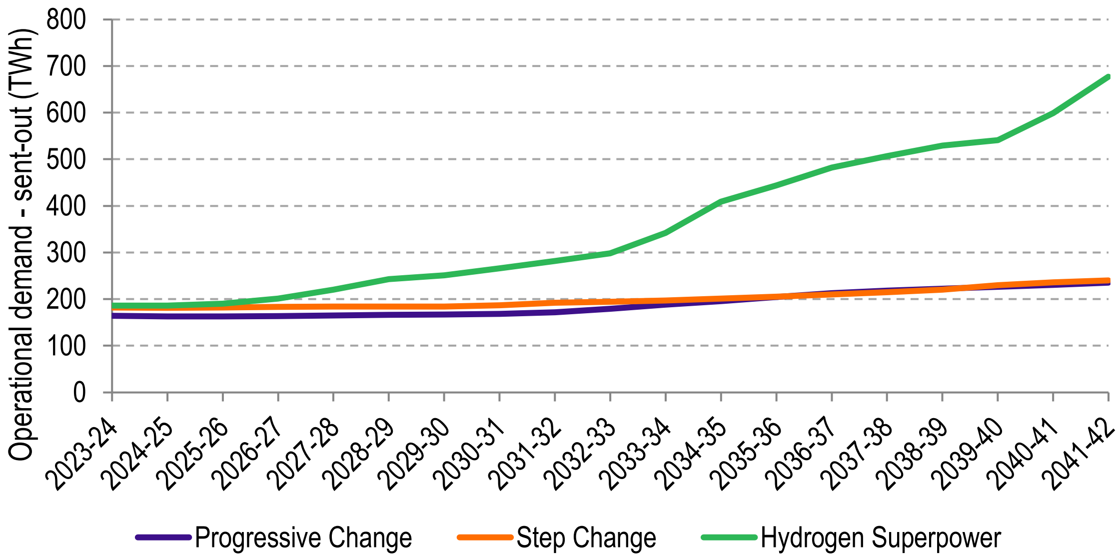
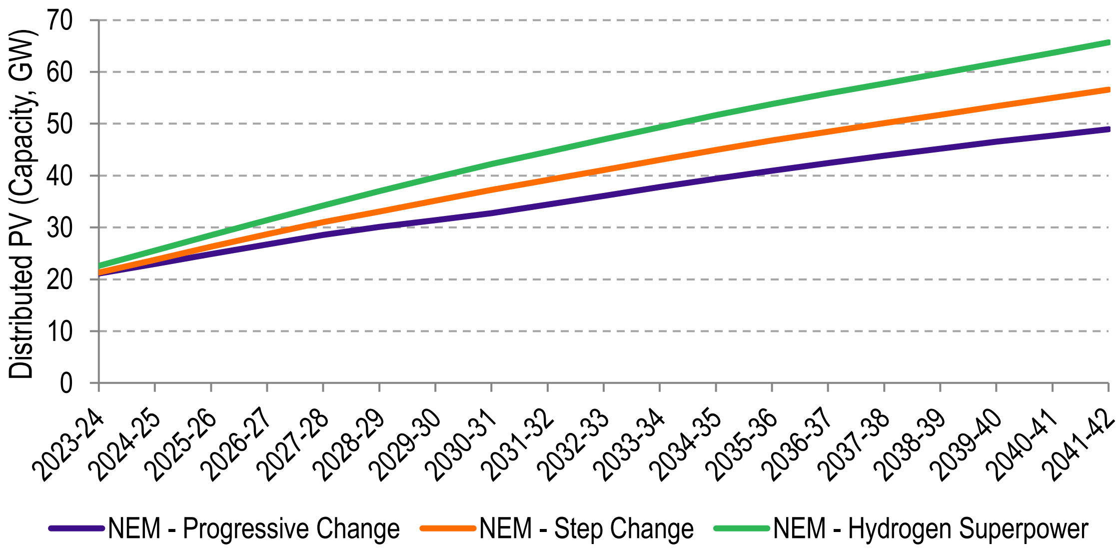


Figure 6: Annual distributed PV (rooftop PV and small non-scheduled PV) uptake in the NEM[8]



The ESOO 2021 demand forecasts for NSW are split into the corresponding zones/nodes that have been defined, as described in Section 5.1. Transgrid obtained from AEMO half-hourly scaling factors to convert regional load to connection point loads which are used to split the regional demand into the zones. Doing so captures the diversity of demand profiles between the different zones in these regions.

6. Supply

6.1 Wind and solar energy projects and REZ representation

Several generators not yet built are committed in all simulations, including the Base Case and each option. The source of this list is the AEMO 2021 ISP Inputs and Assumptions workbook[9], existing, committed and anticipated projects with updates based on new information since the publication of the Draft 2022 ISP[2].

Existing and new wind and solar projects are modelled based on nine years of historical weather data[24]. The methodology for each category of wind and solar project is summarised in Table 10 and explained further in this section of the Report.

Table 10: Summary of wind and solar availability methodology

Technology	Category	Capacity factor methodology	Reference year treatment
Wind	Existing	Specify long-term target based on nine-year average in AEMO ESOO 2019 traces[25] where available, otherwise past meteorological performance.	Capacity factor varies with reference year based on site-specific, historical, near-term wind speed forecasts.
	Committed new entrant	Reference year specific targets based on capacity factor of nearest REZ, medium quality tranche in AEMO's 2021 ISP Inputs and Assumptions workbook[9].	
	Generic REZ new entrants	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[9]. One high quality option and one medium quality trace per REZ.	
Solar PV FFP	Existing	Annual capacity factor based on technology and site-specific solar insolation measurements.	Capacity factor varies with reference year based on historical, site-specific insolation measurements.
Solar PV SAT	Existing		
	Committed new entrant	Reference year specific targets based on capacity factor of nearest REZ, in AEMO's 2021 ISP Inputs and Assumptions workbook[9].	
	Generic REZ new entrant	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[9].	
Rooftop PV and small non-scheduled solar PV	Existing and new entrant	Long-term average capacity factor based on AEMO 2021 ISP Inputs and Assumptions workbook[9].	Capacity factor varies with reference year based on historical insolation measurements.

All existing and committed large-scale wind and solar farms in the NEM are modelled on an individual basis. Each project has a location-specific availability profile based on historical resource availability. The availability profiles are derived using nine years of historical weather data covering financial years between 2010-11 and 2018-19 (inclusive) and synchronised with the hourly shape of demand. Wind and solar availability profiles used in the modelling reflect generation patterns

[24] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 21 June 2022.

[25] AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces* and *2019 Solar Traces*. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo Accessed 21 June 2022.

occurring in the nine historical years, and these generation patterns are repeated throughout the modelling period as shown in Figure 4.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[26] at a representative hub height. Wind speeds are converted into power using a generic wind farm power curve. The wind speed profiles are scaled to achieve the average target capacity factor across the nine historical years. The profiles reflect inter-annual variations, but at the same time achieve long-term capacity factors in line with historical performance (existing wind farms) or the values used in the AEMO 2019 ESOO and draft 2021 ISP inputs and assumptions[9] for each REZ (new entrant wind farms, as listed in Table 11).

The availability profiles for solar are derived using solar irradiation data downloaded from satellite imagery processed by the Australian Bureau of Meteorology. As for wind profiles, the solar profiles reflect inter-annual variations over nine historical years, but at the same time achieve long-term capacity factors in line with historical performance (existing solar farms) or target AEMO's capacity factor for each REZ (generic new entrant solar farms as listed in Table 11).

Table 11: Assumed REZ wind and solar average capacity factors over the nine modelled reference years[9]

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland	Far North Queensland	55%	48%	27%
	North Queensland Clean Energy Hub	44%	37%	30%
	Northern Queensland	Tech not available	Tech not available	28%
	Isaac	37%	32%	28%
	Barcaldine	34%	31%	32%
	Fitzroy	38%	33%	28%
	Wide Bay	32%	31%	26%
	Darling Downs	39%	34%	27%
	Banana	31%	28%	29%
New South Wales	North West NSW	Tech not available	Tech not available	29%
	New England	39%	38%	26%
	Central West Orana	37%	34%	27%
	Broken Hill	33%	31%	30%
	South West NSW	30%	30%	27%
	Wagga Wagga	28%	27%	26%
	Cooma-Monaro	43%	40%	Tech not available
Victoria	Ovens Murray	Tech not available	Tech not available	24%
	Murray River	Tech not available	Tech not available	27%
	Western Victoria	41%	37%	23%

[26] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 21 June 2022.

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
	South West Victoria	41%	39%	Tech not available
	Gippsland[27]	39%	34%	20%
	Central North Victoria	33%	31%	26%
South Australia	South East SA	39%	37%	23%
	Riverland	29%	28%	27%
	Mid-North SA	39%	37%	26%
	Yorke Peninsula	37%	36%	Tech not available
	Northern SA	37%	35%	28%
	Leigh Creek	41%	39%	30%
	Roxby Downs	Tech not available	Tech not available	30%
	Eastern Eyre Peninsula	40%	38%	24%
	Western Eyre Peninsula	39%	38%	27%
Tasmania	North East Tasmania	45%	43%	22%
	North West Tasmania[28]	50%	46%	19%
	Central Highlands	56%	54%	20%

Wind and solar capacity expansion in each REZ is limited by four parameters based on AEMO's 2021 Inputs and Assumptions workbook[9].

- Transmission-limited total build limit (MW) representing the amount of dispatch supported by current intra-regional transmission infrastructure.
- A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre.
- Resource limits (MW) representing the maximum amount of capacity expected to be feasibly developed in a REZ based on topography, land use etc at the given capex.
- A resource limit violation penalty factor ($/MW) to build additional capacity beyond the resource limit. This represents additional capex to build on sites with higher land costs.

The TSIRP model incurs the additional transmission expansion cost to build more capacity up to the resource limit if it is part of the least-cost development plan.

6.2 Generator forced outage rates and maintenance

Full and partial forced outage rates for all generators as well as mean time to repair used in the modelling are based on the AEMO 2021 Inputs and Assumptions workbook[9].

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage

[27] Gippsland has an option for offshore wind with an average capacity factor of 46%.
[28] North West Tasmania has an option for offshore wind with an average capacity factor of 50%.

pattern exists between the Base Case and the various upgrade options. New entrant generators are de-rated by their equivalent forced outage rate.

Planned maintenance events for existing generators are scheduled during low demand periods and the number of days required for maintenance is set based on the AEMO 2021 Inputs and Assumptions workbook[9].

6.3 Generator technical parameters

Technical generator parameters applied are as detailed in the AEMO 2021 Inputs and Assumptions workbook[9] for AEMO's long-term planning model, except as noted in the Report.

6.4 Coal-fired generators

Coal-fired generators are treated as dispatchable between minimum load and maximum load. Must run generation is dispatched whenever available at least at its minimum load. In line with the AEMO 2021 Inputs and Assumptions workbook[9], maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

A maximum capacity factor of 75% is assumed for NSW coal, as per the AEMO 2021 Inputs and Assumptions workbook[9].

6.5 Gas-fired generators

Gas-fired CCGT plant also typically have a must-run component and so are dispatched at or above their minimum load to deliver efficient fuel consumption.

In line with the AEMO 2021 Inputs and Assumptions workbook[9], a minimum load of 46% of capacity for all new CCGTs has been applied to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

OCGTs are assumed to operate with no minimum load. As a result, they start and are dispatched for a minimum of one hour when the cost of supply is at or above their SRMC.

6.6 Wind, solar and run-of-river hydro generators

Intermittent renewables, in particular solar PV, wind and run-of-river hydro are dispatched according to their resource availability as they cannot store energy. Intermittent renewable production levels are based on nine years of hourly measurements and weather observations across the NEM including all REZ zones. Using historical reference years preserves correlations in weather patterns, resource availability and demand. Modelling of wind and solar PV is covered in more detail in Section 6.1.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically, when the marginal cost of supply falls to less than their VOM, or by other constraints such as transmission limits.

6.7 Storage-limited generators

Conventional hydro with storages, PHES and batteries are dispatched in each trading interval such that they are most effective in reducing the costs of generation up to the limits of their storage capacity.

Hourly hydro inflows to the reservoirs and ponds are computed from monthly values sourced from the AEMO 2021 Inputs and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied[10]. The Tasmanian hydro schemes were modelled using a ten-pond model, with additional information sourced from the TasNetworks Input assumptions and scenario workbook for Project Marinus PACR[29].

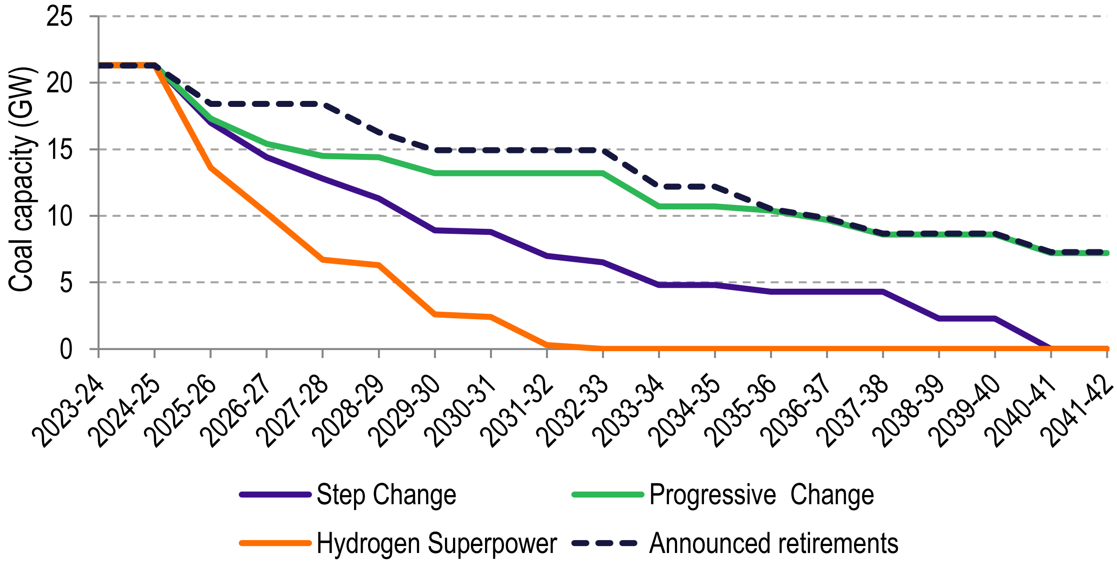
[29] TasNetworks, *Input assumptions and scenario workbook for Project Marinus PACR.* Available at https://www.marinuslink.com.au/rit-t-process/. Accessed on 21 June 2022

7. NEM outlook in the Base Case

Before presenting the forecast benefits of the options, it is useful to understand the expected capacity and generation outlooks in the modelled scenarios, and the underlying input assumptions driving those outlooks in the Base Case without any NWS options.

According to the scenario settings selected by Transgrid and in line with the Draft 2022 ISP, thermal retirements are determined on a least-cost basis. Coal generator retirements occur at or earlier than their end-of-technical-life or announced retirement year. Forecast coal capacity in the Base Case across all scenarios as an output of the modelling is illustrated in Figure 7.

Figure 7: Forecast coal capacity in the NEM by year across all scenarios in the Base Case



The forecast pace of the transition is predominantly determined by a combination of assumed carbon budgets, legislated renewable energy targets (NSW Electricity Infrastructure Roadmap, VRET, QRET and TRET), demand outlook and end-of-life for existing assets in a system developed and dispatched at least cost. The model forecasts the entire coal capacity to retire by the early 2030s in the Hydrogen Superpower scenario, while this is around 2040 for the Step Change scenario. In the Progressive Change scenario, coal-fired generation is forecast to remain until the end of the modelling period, although earlier retirements than AEMO's announced retirements are expected until around the mid-2030s.

The NEM-wide capacity mix forecast in the Base Case for the Step Change scenario is shown in Figure 8 and the corresponding generation mix in Figure 9. In the Base Case, the forecast generation capacity of the NEM shifts towards increasing capacity of wind and solar, complemented by large-scale battery, PHES, and gas.

Figure 8: NEM capacity mix forecast for the Step Change scenario in the Base Case

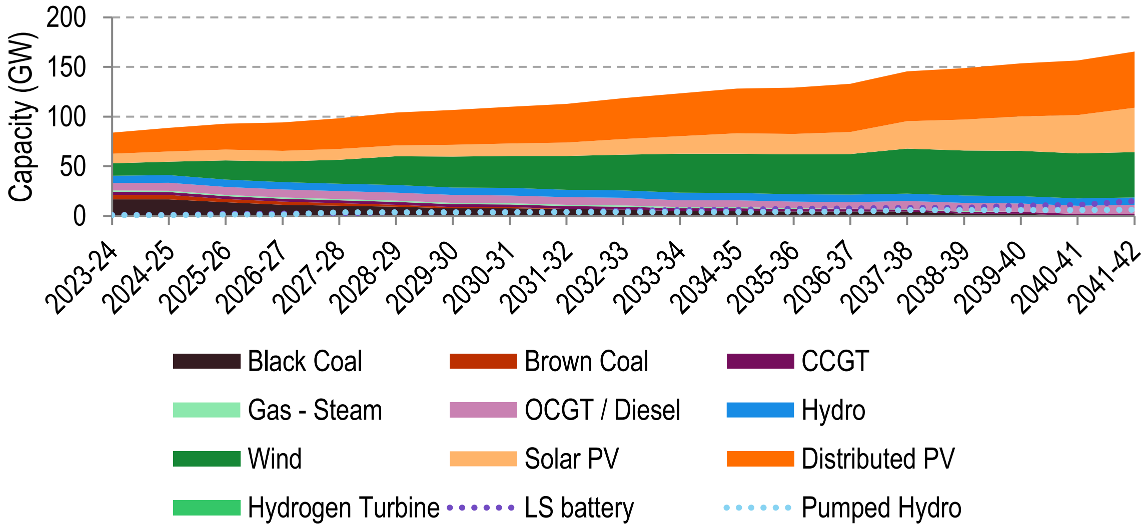
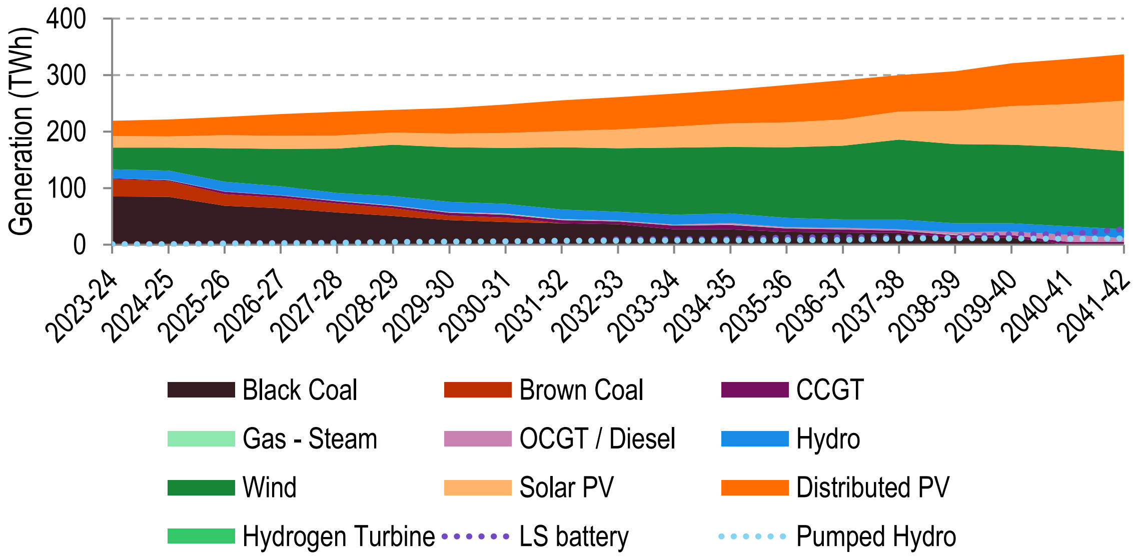


Figure 9: NEM generation mix forecast for the Step Change scenario in the Base Case



Up to 2030, new wind and solar build is largely driven by the assumed state-based renewable energy targets as well as the new renewable capacity to replace early coal retirement. The forecast increase in renewable capacity leads to some earlier coal generation retirements[30] in Queensland and NSW. To replace the retiring capacity, large-scale battery capacity is forecast to start to increase from the late 2020s, then PHES and wind capacity increases from the mid-2030s. Solar PV and OCGT capacity is also forecast to increase from the late 2030s complementing other technologies. The forecast gas-fired capacity also supports reserve requirements. Overall, the NEM is forecast to have around 186 GW total capacity by 2041-42 (note that total capacity includes distributed PV, which is an input assumption, and also PHES and large-scale battery capacities, which are not in the stacked chart). The forecast timing of entry of the majority of new installed capacity coincides with coal-fired generation retirements.

The other selected scenarios vary in the pace of the energy transition from the Step Change scenario. Figure 10 and Figure 12 show the differences in the NEM capacity development of other scenarios relative to the Step Change scenario, while Figure 11 and Figure 13 show generation differences. The differences are presented as alternative scenario minus the Step Change scenario,

[30] Note that the earlier coal retirements in TSIRP is based on the least cost optimisation, rather than revenue assessment.

and both capacity and generation differences for each scenario show similar trends. As the figures show, Progressive Change scenario retains higher coal generation and less wind and solar generation compared to the Step Change scenario due to different assumptions such as the less restrictive carbon budget, demand forecast and other underlying input data. The Hydrogen Superpower scenario has higher wind, solar and large-scale battery while less OCGT capacity and generation compared to the Step Change scenario, mainly due to the significant hydrogen demand uptake in this scenario, along with a more restrictive carbon budget.

Figure 10 Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios in the Base case (excluding distributed PV)

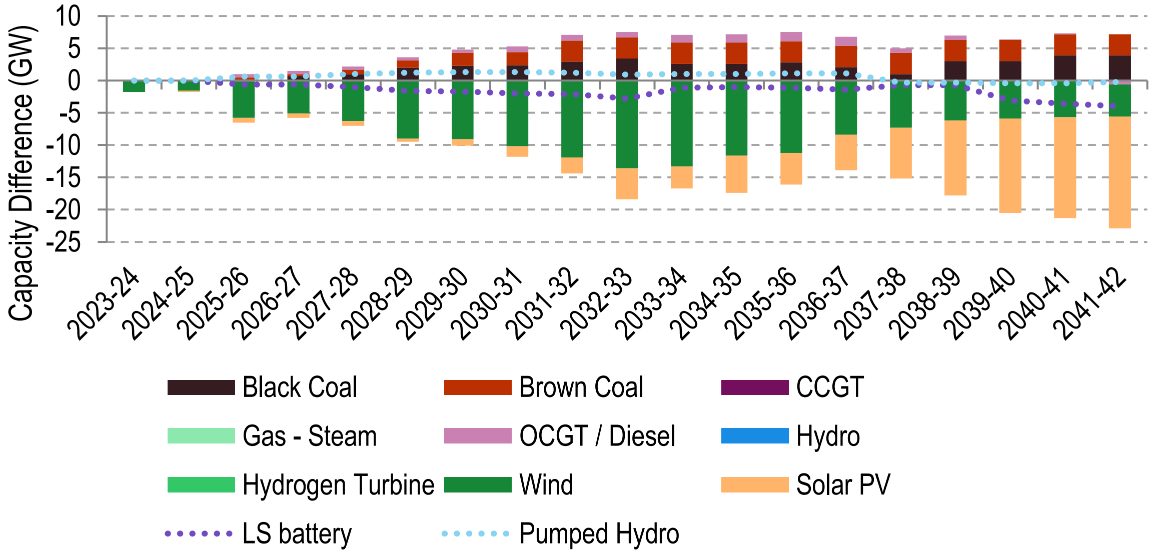


Figure 11 Difference in NEM generation forecast between the Progressive Change and Step Changes scenarios in the Base case (excluding distributed PV)

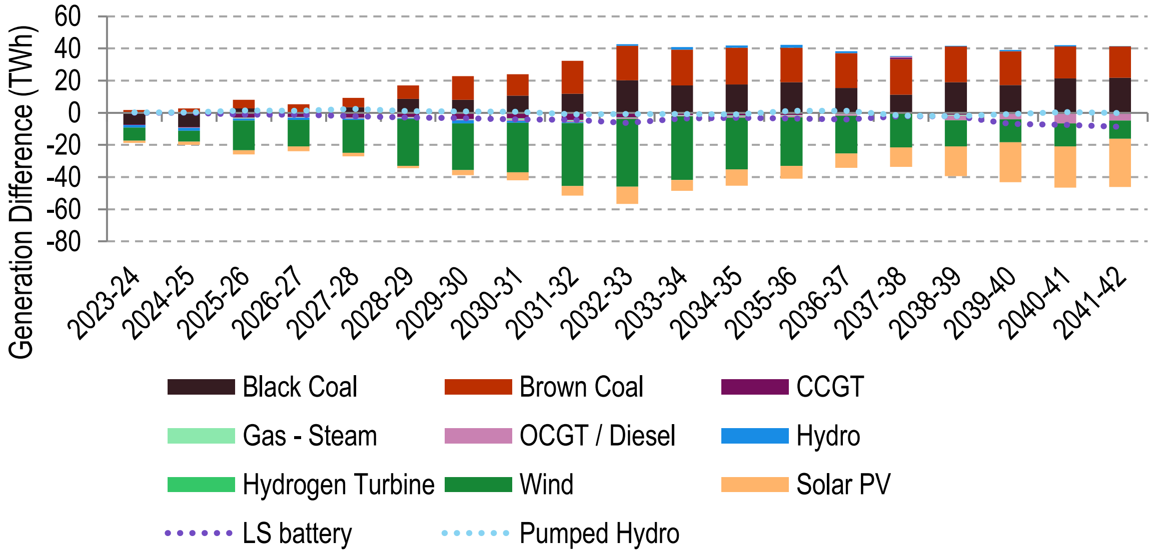


Figure 12 Difference in NEM capacity forecast between the Hydrogen Superpower and Step Change scenarios in the Base case (excluding distributed PV)

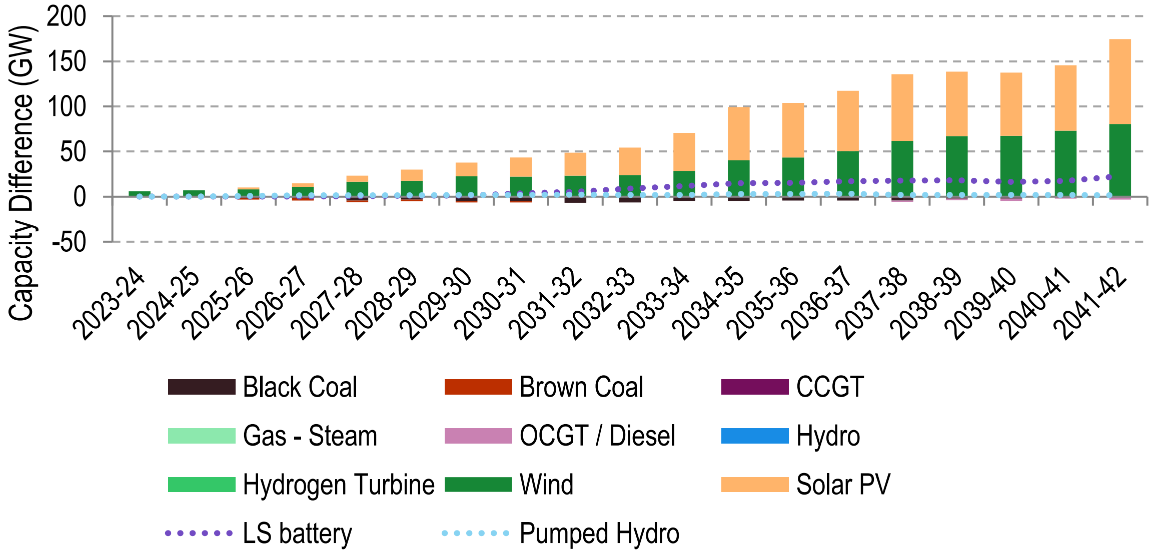
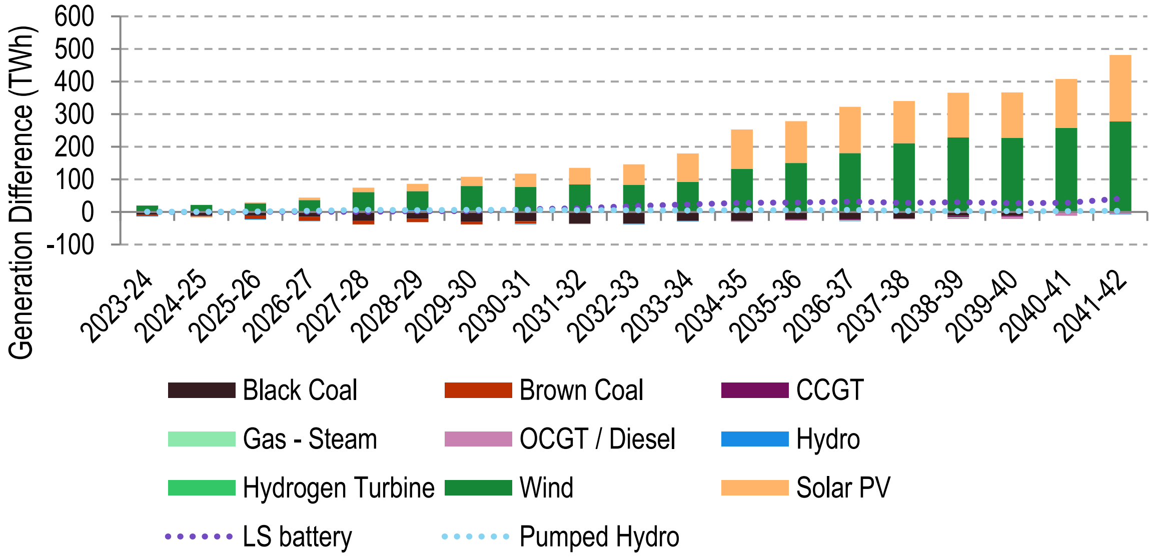


Figure 13 Difference in NEM generation forecast between the Hydrogen Superpower and Step Change scenarios in the Base case (excluding distributed PV)



8. Forecast gross market benefit outcomes

Throughout this section, the y-axis in all the comparison charts is removed to maintain the confidentiality of the modelled options as requested by Transgrid. It is important to note that the 'y' axis scale is not an equal representation among the scenarios/options. Consequently, the graphs should not be used to compare magnitude of results between the scenarios/options.

Given the similarity of the results for Options 5A, 5B and 5C, we only present the results for one option in this group. Option 3B's results are provided separately. Note that all capacity and generation charts in the following sections include the modelled battery for the relevant options.

The difference in forecast market benefits across scenarios varies with the option; Progressive Change has the highest forecast market benefits for all options, while Step Change has the lowest forecast market benefits. The breakdown of forecast gross market benefits by category for all modelled options in the three modelled scenarios are shown in Figure 14 to Figure 16.

Figure 14: Composition of forecast total gross market benefits for all options – Step Change

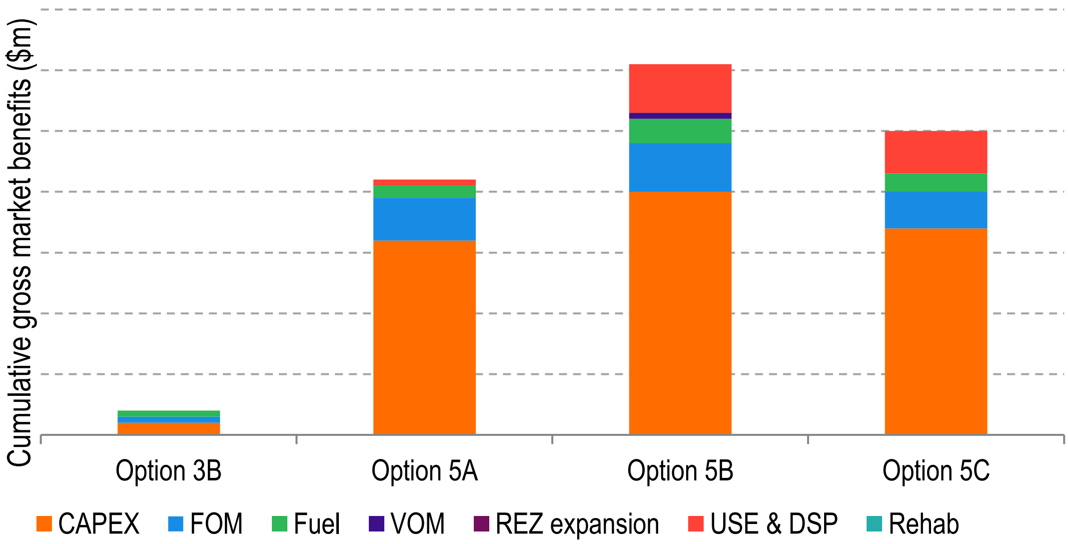


Figure 15: Composition of forecast total gross market benefits for all options – Progressive Change

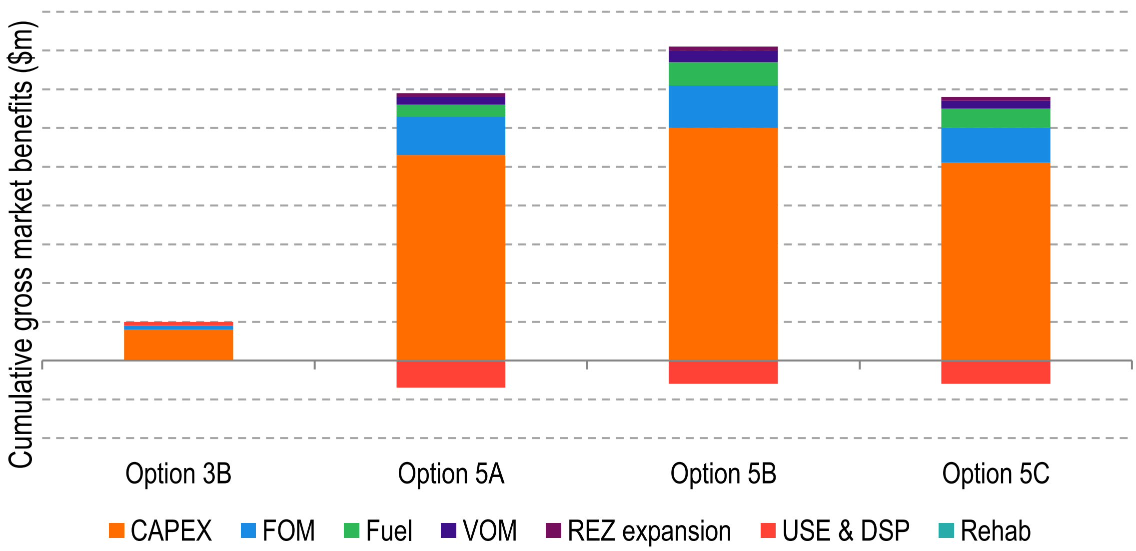
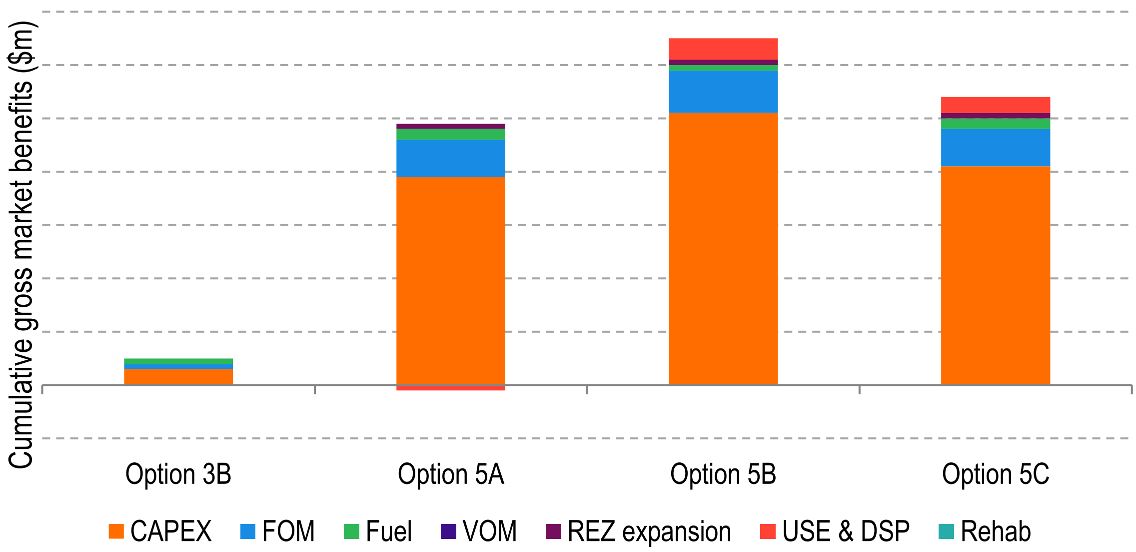


Figure 16: Composition of forecast total gross market benefits for all options – Hydrogen Superpower



The sources of forecast benefits and the key drivers are as follows:

- Capex and FOM cost savings are the largest source of forecast market benefits in all scenarios. Cost savings from avoided USE and DSP are forecast to be relatively high with Options 5B and 5C in the Step Change and Hydrogen Superpower scenarios, while the Progressive Change scenario is expected to incur some costs associated with increased USE and DSP with all options relative to the Base Case.
- All options are assumed to have arbitrage capability during winter, whereas some options can also provide arbitrage during summer. This results in avoiding some OCGT build which is required in the Base Case in the Progressive Change scenario. This is expected to result in early benefits for this option in this scenario, as opposed to the later benefits in other scenarios, leading to higher benefits in the Progressive Change scenario.

8.1 Market modelling results for Option 3B

8.1.1 Step Change scenario

The forecast cumulative gross market benefits of Option 3B in the Step Change scenario are depicted in Figure 17. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 3B and the Base Case in the same scenario are shown in Figure 18 and Figure 19, respectively.

Figure 17: Forecast cumulative gross market benefit[31] for Option 3B under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

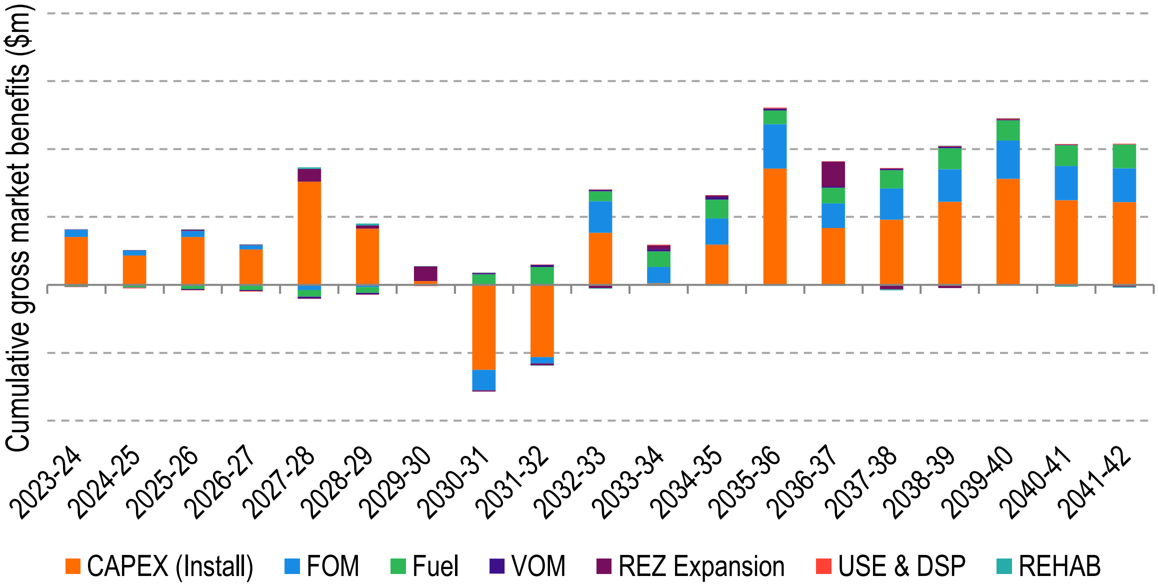


Figure 18: Difference in NEM capacity forecast between Option 3B and Base Case in the Step Change scenario

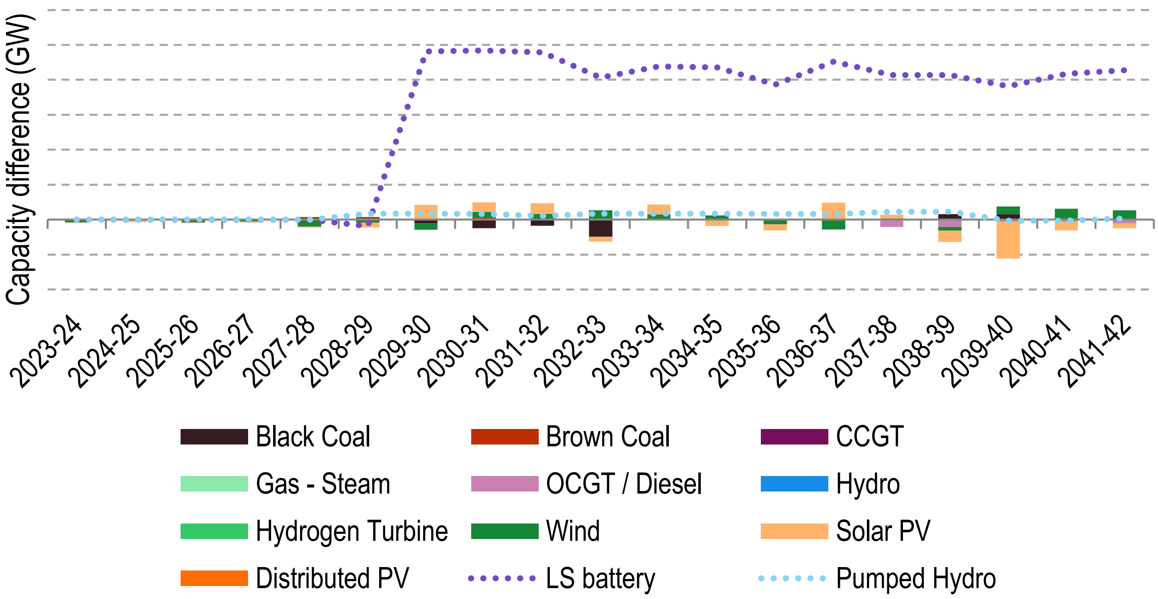
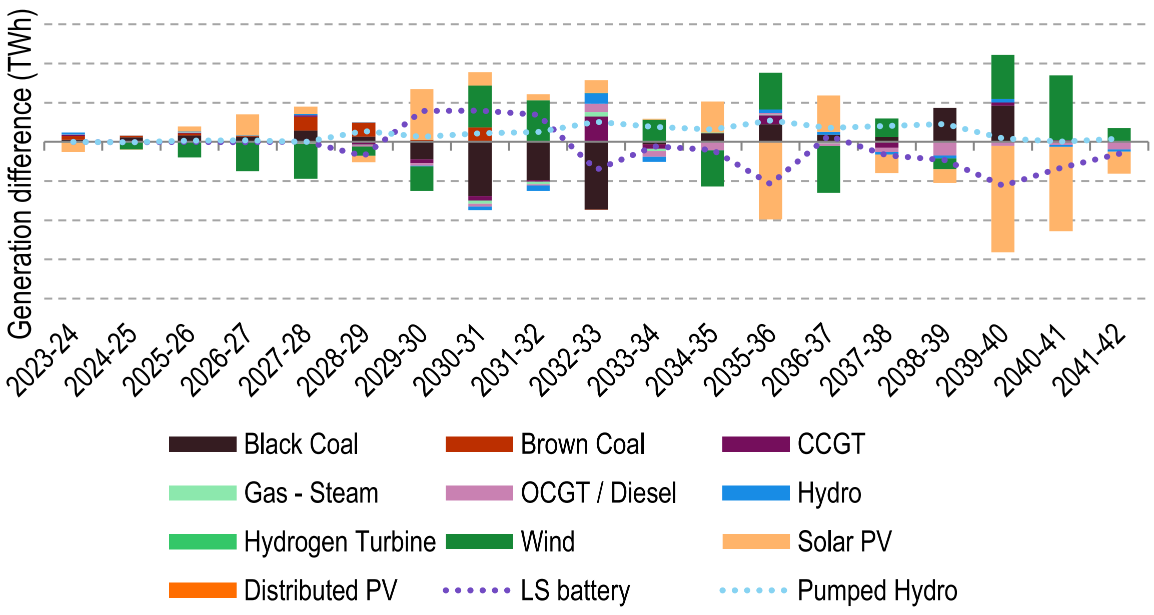


Figure 19: Difference in NEM generation forecast between Option 3B and Base Case in the Step Change scenario



With Option 3B in place in the Step Change scenario the primary sources of benefits are forecast to be capex and FOM cost savings, followed by fuel cost savings. The timing and source of these benefits are attributable to the following:

- Capex and FOM cost savings are mostly due to the forecast deferral of some investment in solar and wind as well as deferral/avoidance of large-scale battery in 2030s.
- Some fuel cost savings are expected, mostly due to less gas production in Option 3B.

8.1.2 Progressive Change scenario

The forecast cumulative gross market benefits of Option 3B in the Progressive Change scenario are shown in Figure 20. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 3B and the Base Case are shown in Figure 21 and Figure 22.

Figure 20: Forecast cumulative gross market benefit[31] for Option 3B under the Progressive Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

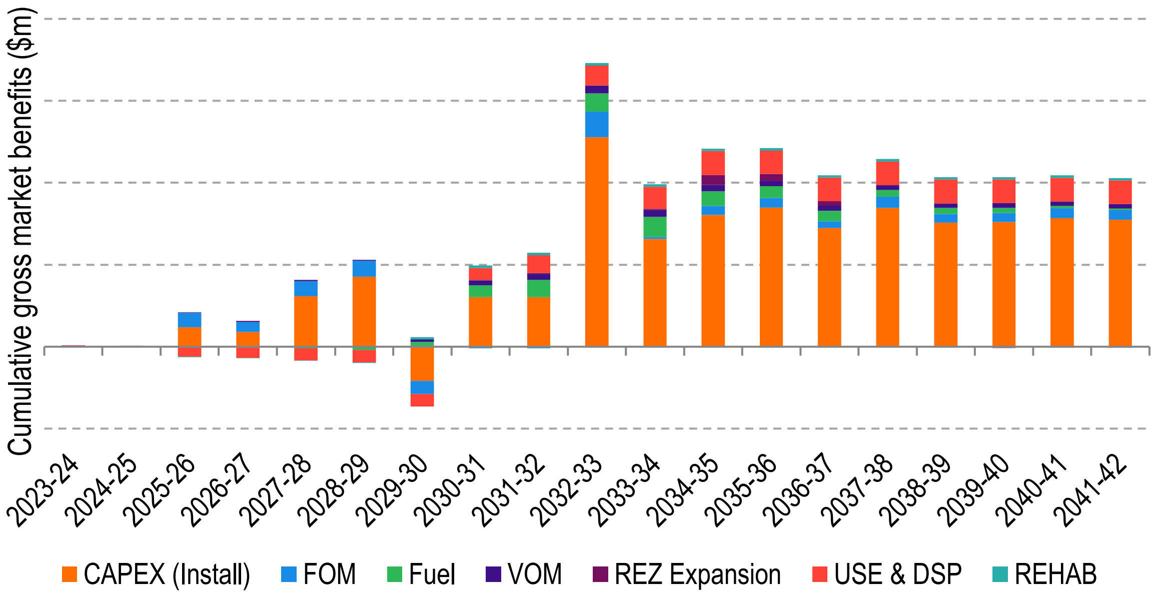


Figure 21: Difference in NEM capacity forecast between Option 3B and Base Case in the Progressive Change scenario

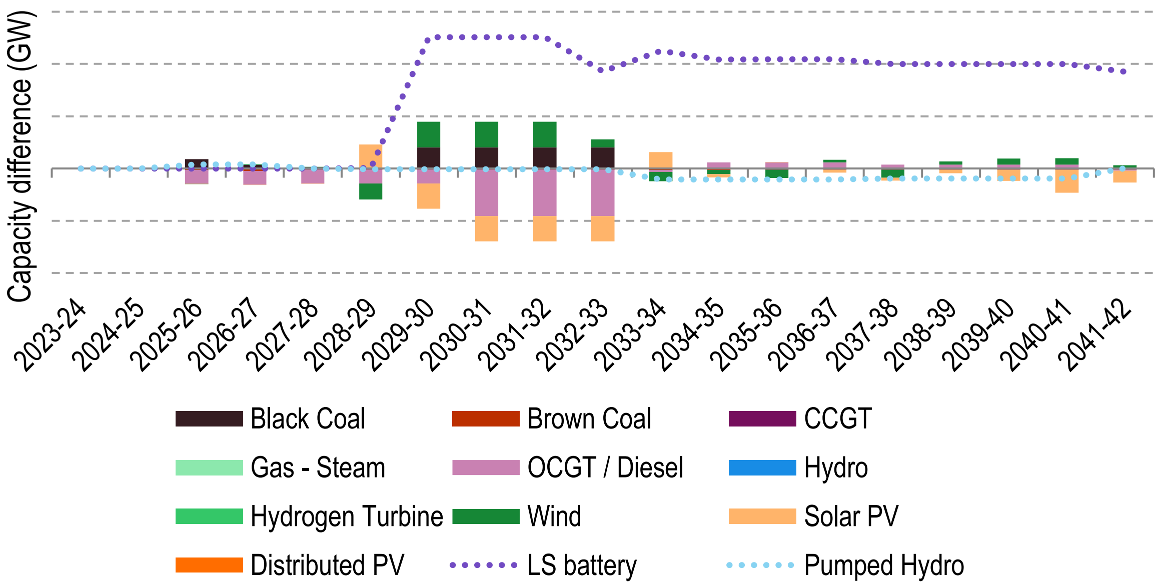
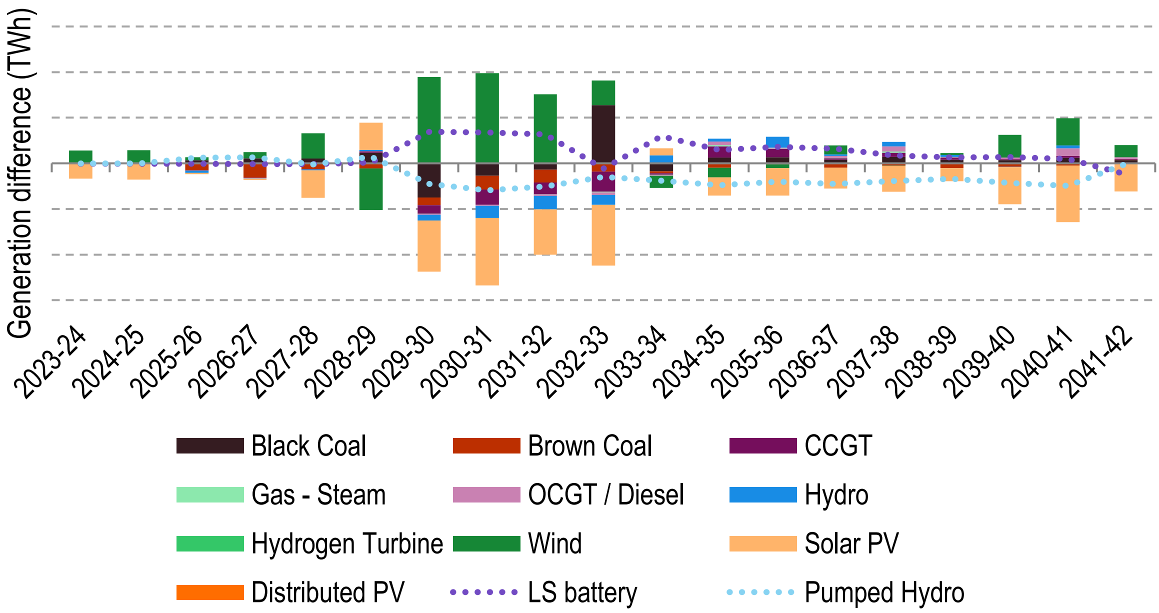


Figure 22: Difference in NEM generation forecast between Option 3B and Base Case in the Progressive Change scenario



The primary source of forecast market benefits in the Progressive Change scenario are from avoided and deferred capex followed by USE and DSP savings. The timing and source of these benefits are attributable to the following:

- This option is forecast to defer some OCGT capacity from 2025-26, and more from 2030-31 until 2033-34 which results in capex savings accruing over this period. In addition, this option is expected to reduce investment in large-scale battery capacity from the early 2030s which also results in additional capex savings.
- In the Progressive Change Base Case, OCGT capacity is required in NSW to meet high demand periods in winter and summer. With Option 3B, some OCGT capacity is deferred from 2025-26 through to 2029-30 in favour of incurring some USE and DSP costs. Once the Option 3B battery is commissioned in 2029-30, its ability to arbitrage in winter allows for additional OCGT capacity deferral from 2030-31 through to 2032-33, resulting in capex and FOM cost savings as well as USE and DSP savings over this period.

8.1.3 Hydrogen Superpower scenario

The forecast cumulative gross market benefits of Option 3B in the Hydrogen Superpower scenario are shown in Figure 23. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 3B and the Base Case in this scenario are shown in Figure 24 and Figure 25.

Figure 23: Forecast cumulative gross market benefit[31] for Option 3B under the Hydrogen Superpower scenario, millions real June 2021 dollars discounted to June 2021 dollars

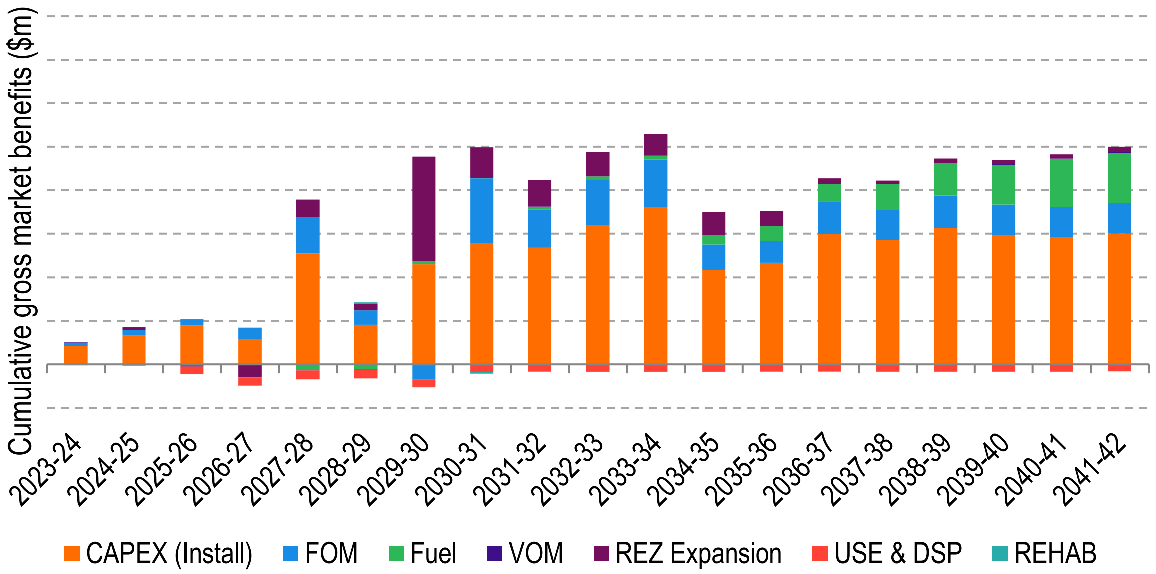


Figure 24: Difference in the NEM capacity forecast between Option 3B and Base Case in the Hydrogen Superpower scenario

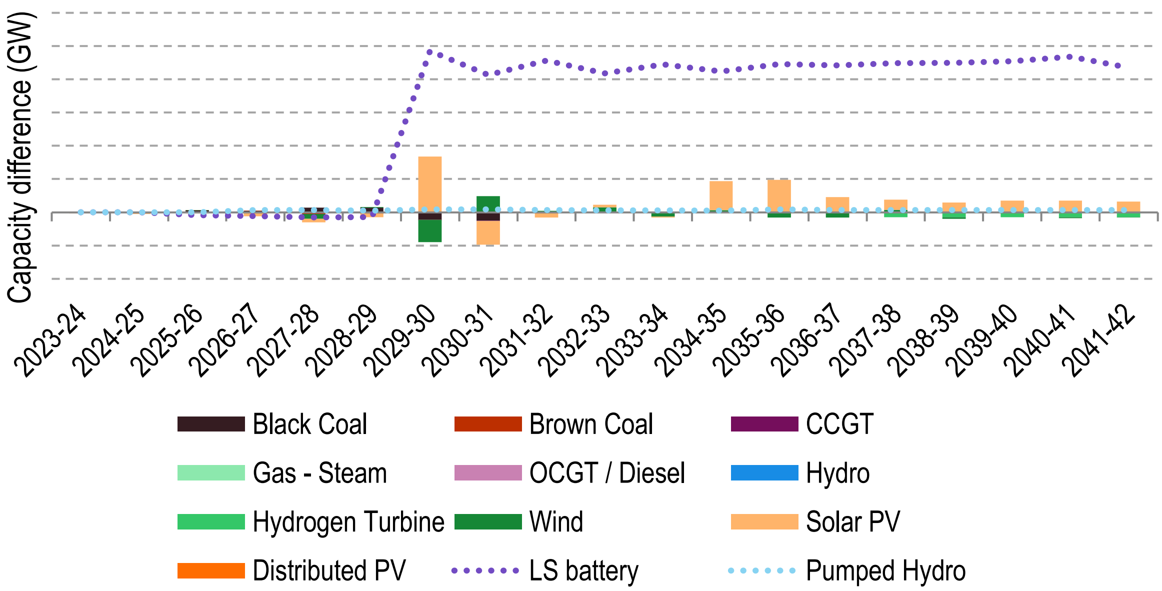
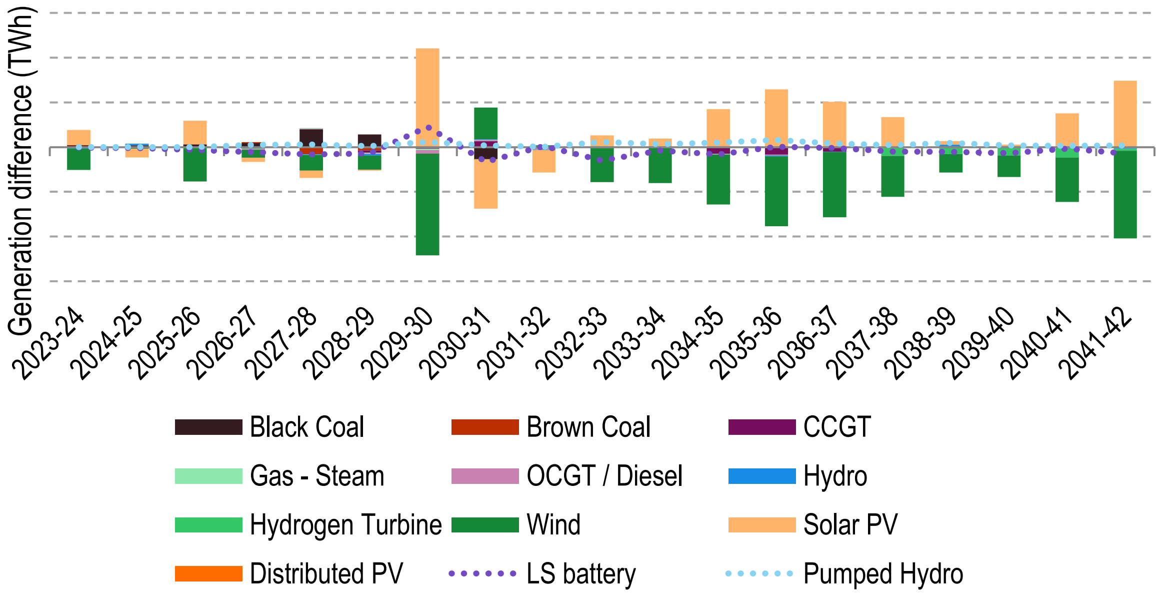


Figure 25: Difference in NEM generation forecast between Option 3B and Base Case in the Hydrogen Superpower scenario



In the Hydrogen Superpower scenario, the primary sources of forecast market benefits for Option 3B are from capex and FOM cost savings followed by fuel cost savings. The timing and source of these benefits are attributable to the following:

- Capex and FOM cost savings are forecast to accrue from the first year of the study through to the end of the study. These benefits can be attributed to avoiding large-scale battery capacity with the Option 3B battery in place.
- Fuel cost savings are forecast to begin accruing in the early 2030s but become most significant in the late 2030s and into the 2040s. These fuel cost savings are a result decreased hydrogen turbine generation with the Option 3B battery in place.

8.2 Market modelling results for Option 5B

This section presents the results for Option 5B. Option 5A and Option 5C displayed similar results to this option.

8.2.1 Step Change scenario

The forecast cumulative gross market benefits of Option 5B in the Step Change scenario are depicted in Figure 26. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 5B and the Base Case in the same scenario are shown in Figure 27 and Figure 28, respectively.

Figure 26: Forecast cumulative gross market benefit[31] for Option 5B under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

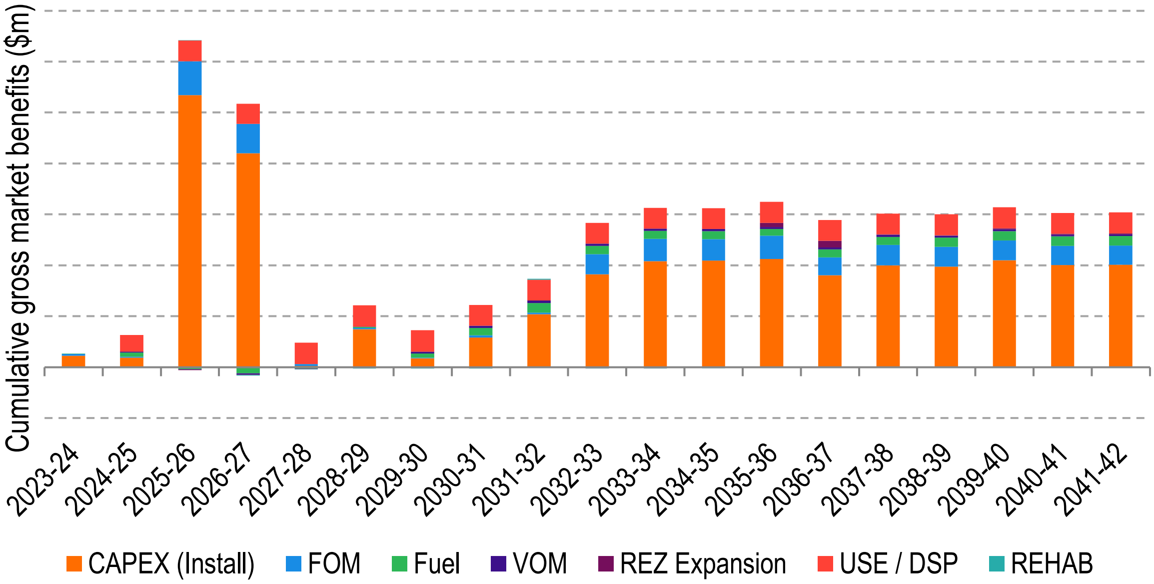
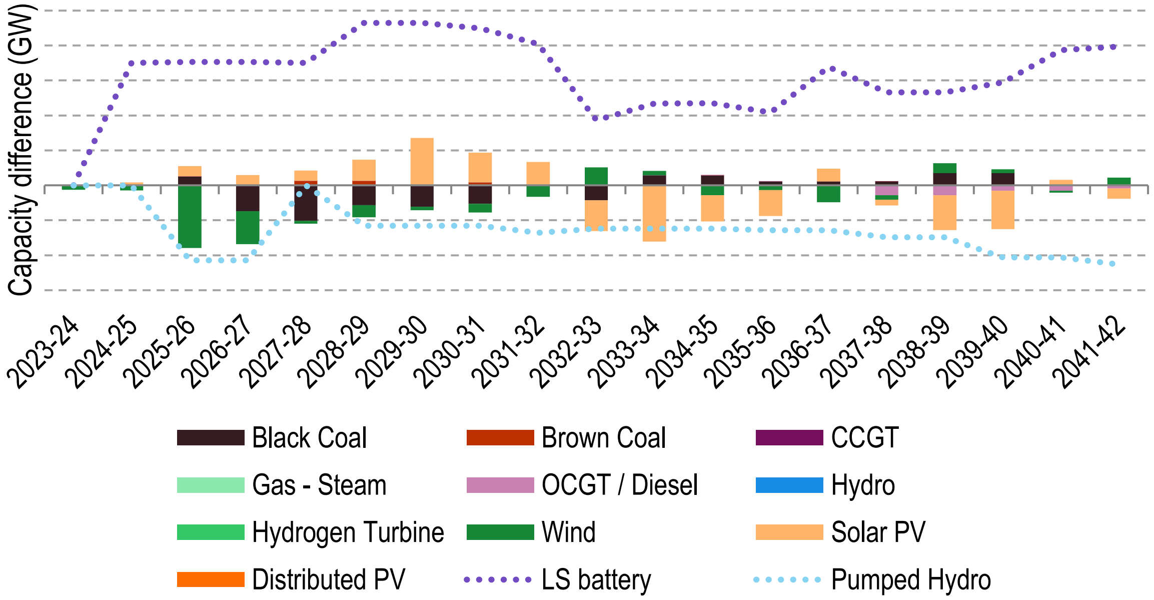
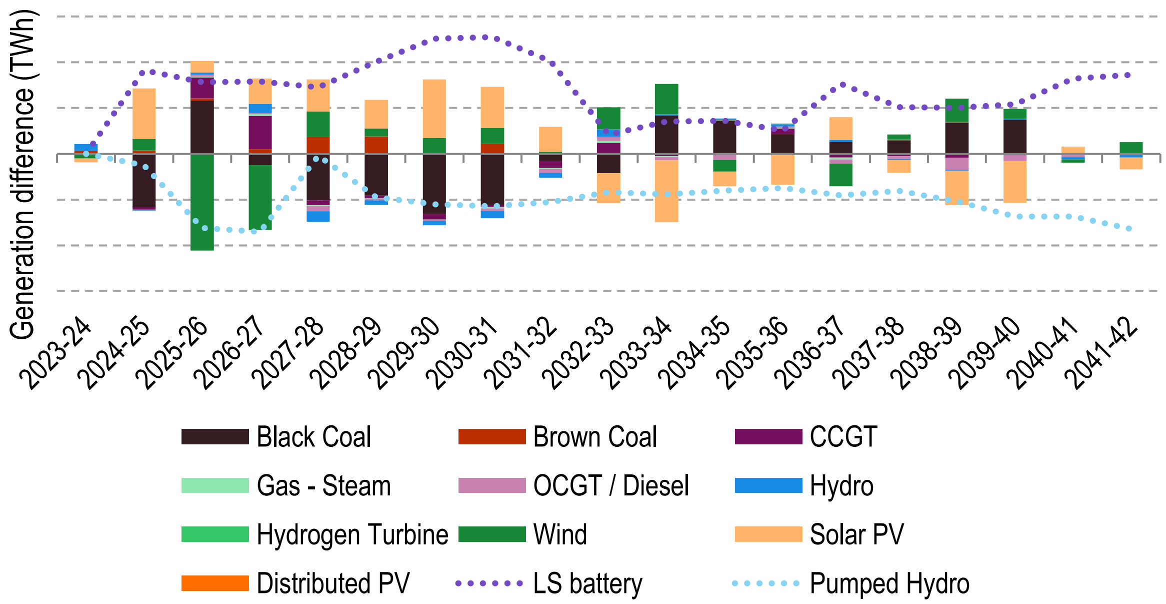


Figure 27: Difference in NEM capacity forecast between Option 5B and Base Case in the Step Change scenario



[31] Note that all generator and storage capital costs have been included in the market modelling on an annualised basis. However, this chart and all charts of this nature in the Report present the entire capital costs of these plants in the year avoided to highlight the timing of capacity changes that drive expected capex benefits. This is purely a presentational choice that Transgrid has made to assist with relaying the timing of expected benefits (i.e., when thermal plant retires) and does not affect the overall gross benefits of the options.

Figure 28: Difference in NEM generation forecast between Option 5B and Base Case in the Step Change scenario



The forecast gross market benefits in the Step Change scenario are made up of capex and FOM cost savings from deferred and avoided capacity followed by some USE and DSP savings. The timing and source of these benefits are as follows:

- The Option 5B battery is forecast to enable additional solar and wind generation through the late 2020s and early 2030s which offsets black coal and gas generation, reducing emissions in this period. As the modelled emissions budget is applied over the whole modelling horizon, reduced emissions in one period can allow for increased emissions in another period. The reduced black coal and gas generation in the late 2020s and early 2030s allows for increased black coal and gas generation from 2025 to 2027 and from 2032 to 2040, which allows for deferral of new capacity in these periods.
- Capex benefits are forecast to begin to accrue again from 2027-28 through to the early 2030s primarily due to the avoidance of PHES capacity and additionally due to the deferral of wind capacity.
- The commissioning of the Option 5B battery in 2024-25 is forecast to result in some USE and DSP savings within NSW in the same year.

8.2.2 Progressive Change scenario

The forecast cumulative gross market benefits of Option 5B in the Progressive Change scenario are shown in Figure 29. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 5B and the Base Case are shown in Figure 30 and Figure 31.

Figure 29: Forecast cumulative gross market benefit[31] for Option 5B under the Progressive Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

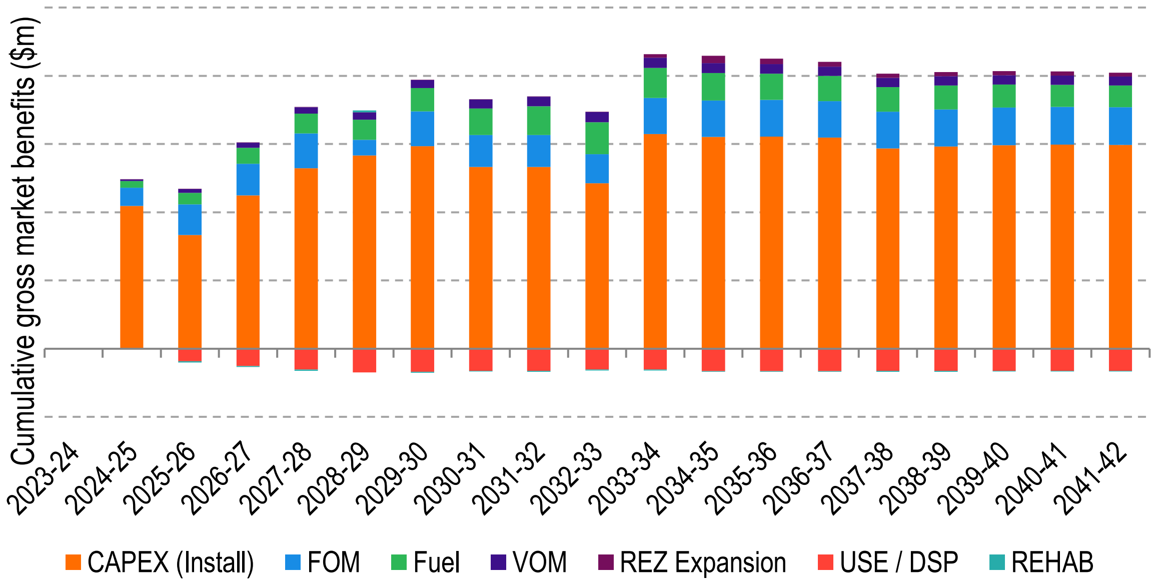


Figure 30: Difference in NEM capacity forecast between Option 5B and Base Case in the Progressive Change scenario

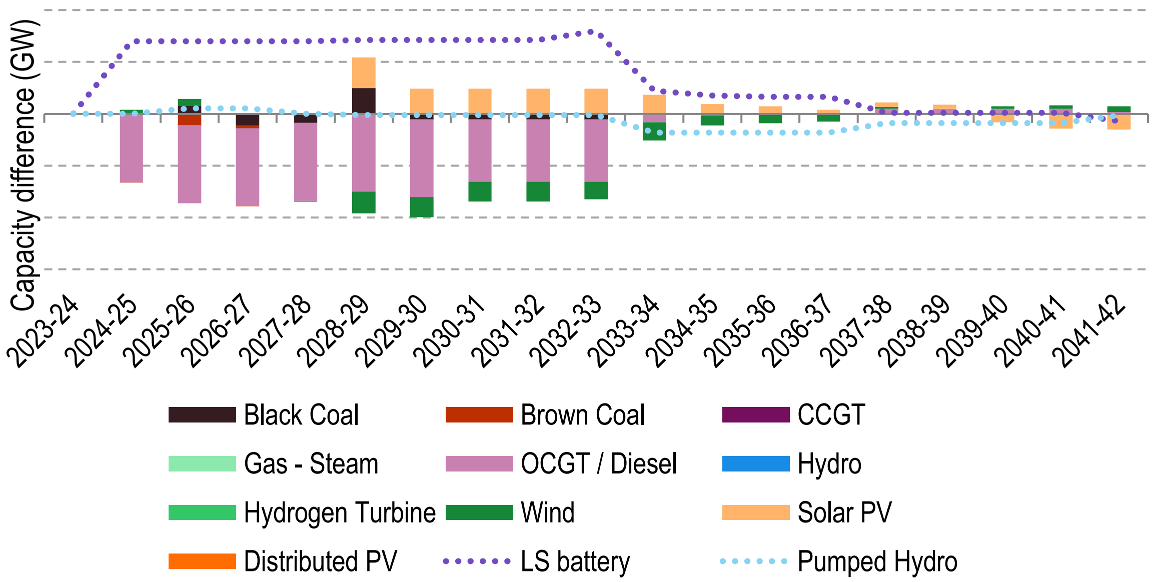
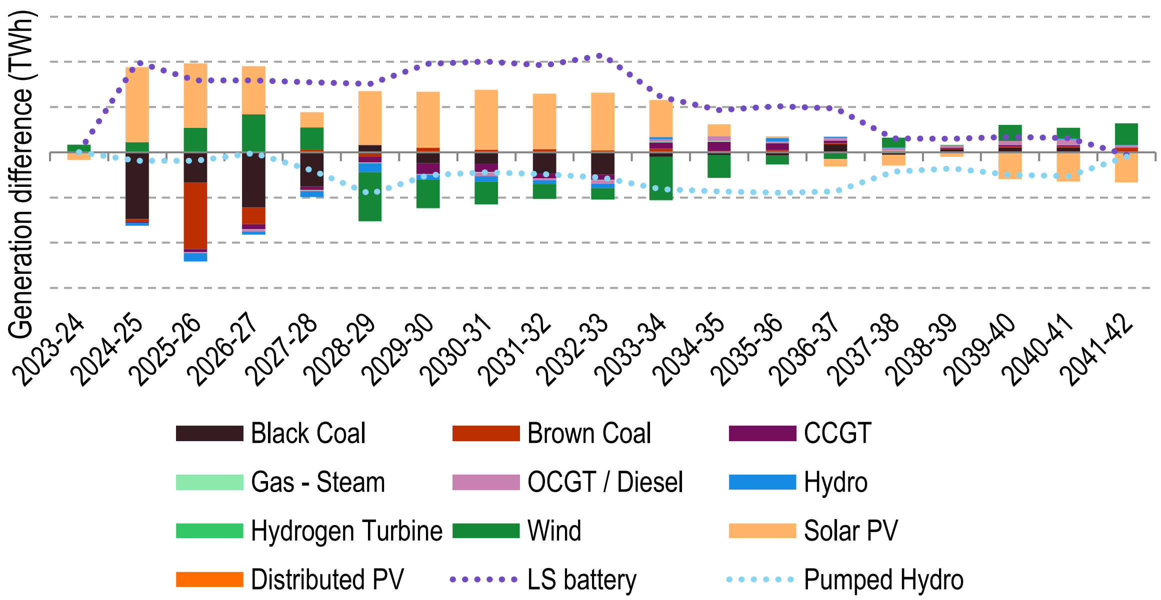


Figure 31: Difference in NEM generation forecast between Option 5B and Base Case in the Progressive Change scenario



The forecast gross market benefits in the Progressive Change scenario are made up of capex and FOM savings from deferred and avoided capacity build and reduced fuel costs. A summary of the drivers as well as timing and sources of benefits for this option is as follows:

- In the Base Case OCGT capacity is required in NSW to meet demand and reserve requirements during high demand periods in winter and summer. The Option 5B battery is able to arbitrage in winter allowing for the deferral of OCGT capacity from 2024-25 through to the early 2030s, resulting in capex and FOM cost savings over this period.
- Additionally, in the late 2020s to early 2030s the Option 5B battery is forecast to enable solar capacity to be built instead of more expensive wind capacity, resulting in additional capex savings.
- Option 5B battery is forecast to enable additional generation from existing wind and solar capacity to 2027-28 which displaces black and brown coal-fired generation. This results in some fuel cost savings over this period.

8.2.3 Hydrogen Superpower scenario

The forecast cumulative gross market benefits of Option 5B in the Hydrogen Superpower scenario are shown in Figure 32. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 5B and the Base Case in this scenario are shown in Figure 33 and Figure 34.

Figure 32: Forecast cumulative gross market benefit[31] for Option 5B under the Hydrogen Superpower scenario, millions real June 2021 dollars discounted to June 2021 dollars

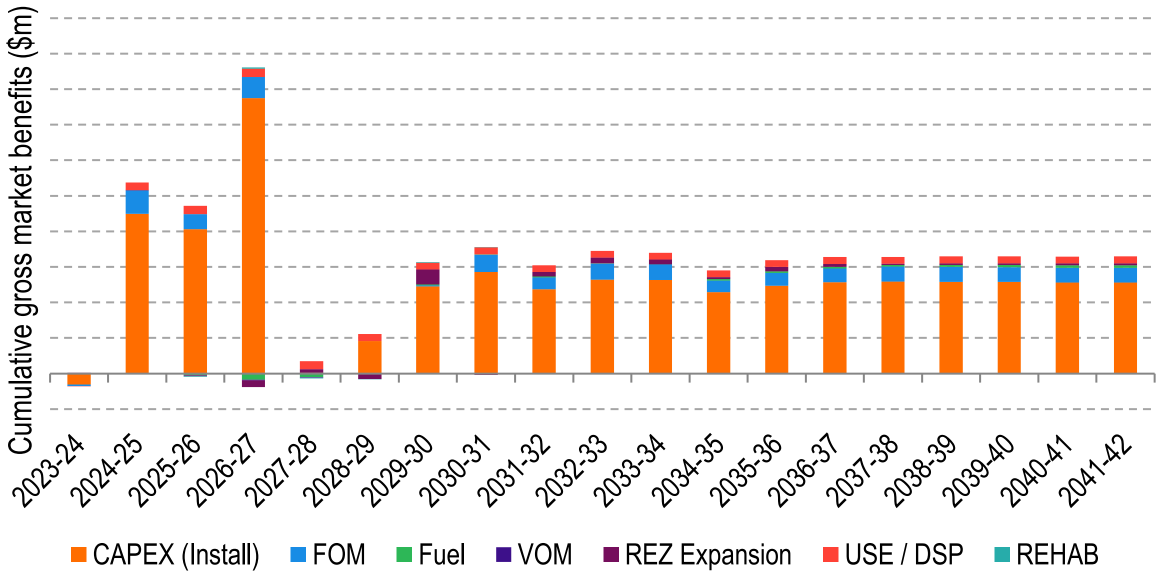


Figure 33: Difference in the NEM capacity forecast between Option 5B and Base Case in the Hydrogen Superpower scenario

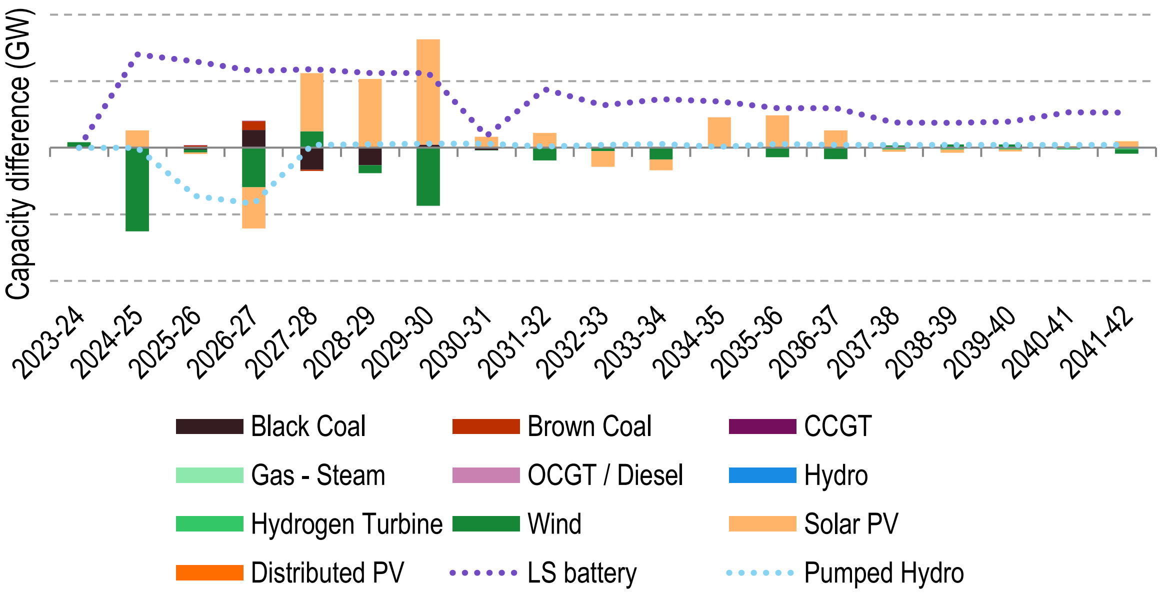
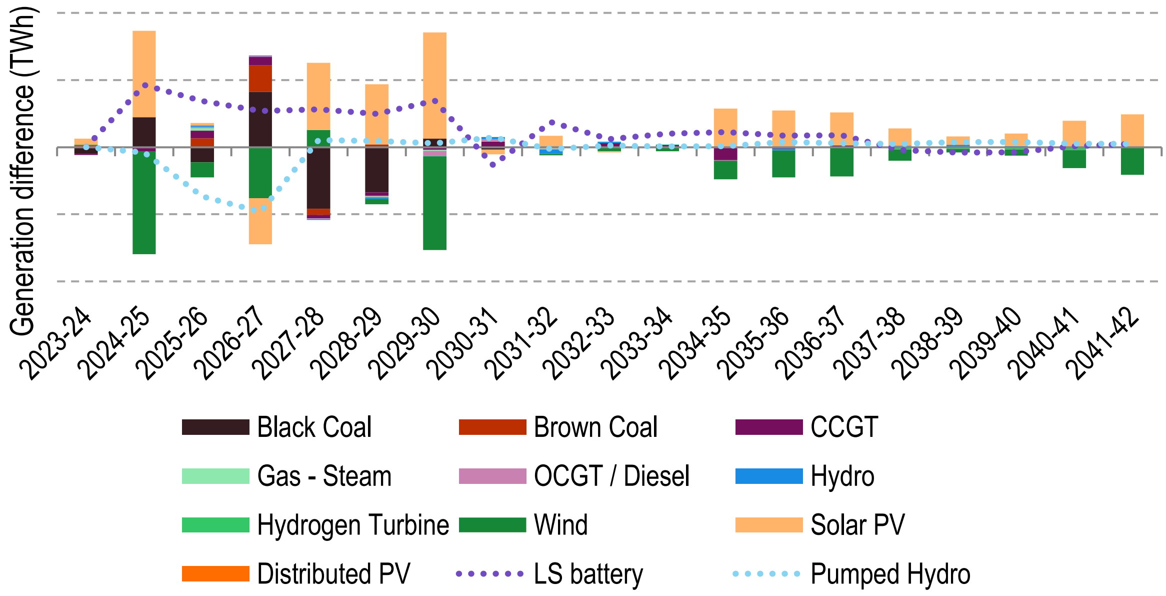


Figure 34: Difference in NEM generation forecast between Option 5B and Base Case in the Hydrogen Superpower scenario



The majority of forecast gross market benefits in the Hydrogen Superpower scenario are derived from capex and FOM cost savings due to deferred and avoided capacity and replacement of new wind with cheaper solar PV. The timing and source of these benefits are attributable to the following:

- Capex and FOM cost savings are mostly forecast from the late 2020s, due to the deferral of wind capacity and deferral/avoidance of investment in large-scale battery.

Appendix A Glossary of terms

Abbreviation	Meaning
AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australia Energy Regulator
$b	Billion dollars
CAN	Canberra (NEM zone)
CAPEX	Capital Expenditure
CO_2	Carbon Dioxide
CCGT	Combined-Cycle Gas Turbine
CWO	Central West Orana
DC	Direct Current
DSP	Demand side participation
ESOO	Electricity Statement of Opportunities
FFP	Fixed Flat Plate (in relation to solar PV)
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
LHS	Left Hand Side
LS Battery	Large-Scale battery storage (as distinct from behind-the-meter battery storage)
$m	Million dollars
Mt	Mega Ton
MW	Megawatt
MWh	Megawatt-hour
NCEN	Central New South Wales (NEM zone)
NEM	National Electricity Market
NNS	Northern New South Wales (NEM zone)
NPV	Net Present Value
NSW	New South Wales
NWS	North West Slopes
OCGT	Open-Cycle Gas Turbine
PACR	Project Assessment Conclusion Report

Abbreviation	Meaning
PADR	Project Assessment Draft Report
PEC	Project EnergyConnect
PHES	Pumped Hydro Energy Storage
PV	Photovoltaic
PV	Present Value
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QNI Minor	NSW to QLD Interconnector Upgrade
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
RHS	Right Hand Side
SA	South Australia
SAT	Single Axis Tracking (in relation to solar PV)
STATCOM	Static Synchronous Compensator
SRMC	Short-Run Marginal Cost
SWNSW	South West New South Wales (NEM zone)
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
TSIRP	Time-sequential integrated resource planner
TW	Terawatt
TWh	Terawatt-hour
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRE	Variable Renewable Energy
VRET	Victoria Renewable Energy Target
VPP	Virtual Power Plant

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